TECHNICAL
REPORT
JUNE 1984

BRITISH COLUMBIA ENERGY SUPPLY AND REQUIREMENTS FORECAST 1982–2000

Province of
British Columbia

Ministry of
Energy, Mines and
Petroleum Resources

Hon. C. Stephen Rogers
Minister

85-0642/

TECHNICAL REPORT

BRITISH COLUMBIA ENERGY SUPPLY AND REQUIREMENTS FORECAST

1982-2000

PREPARED BY:
FORECASTS AND SPECIAL PROJECTS BRANCH
ENERGY RESOURCES DIVISION
MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES

JUNE 1984

Table of Contents

INTRODUCTION

Page

CHAPTER 1: EXECUTIVE SUMMARY 1-1

CHAPTER 2: EXOGENOUS VARIABLES 2-1

- 2.1) Economic and Demographic Variables 2-1
- 2.2) Energy Prices. 2-10

CHAPTER 3: RESIDENTIAL SECTOR. 3-1

CHAPTER 4: COMMERCIAL SECTOR 4-1

CHAPTER 5: INDUSTRIAL SECTOR 5-1

- 5.0) Industrial Sector Overview 5-1
- 5.1) Forestry 5-6
- 5.2) Primary Metals 5-28
- 5.3) Chemicals. 5-33
- 5.4) Non-Metallic Minerals 5-36
- 5.5) Petroleum Refineries 5-41
- 5.6) Petrochemicals/LNG 5-45
- 5.7) Other Manufacturing 5-48
- 5.8) Mining 5-52
- 5.9) Other Industrial 5-61

Page

CHAPTER 6: TRANSPORTATION SECTOR 6-1
6.0) Transportation Sector Overview . . 6-1
6.1) Road 6-2
6.2) Rail 6-23
6.3) Marine 6-29
6.4) Air 6-35

CHAPTER 7: NON-ENERGY USE. 7-1

CHAPTER 8: TOTAL ENERGY REQUIREMENTS 8-1

CHAPTER 9: CONVENTIONAL ENERGY SUPPLIES. 9-1

CHAPTER 10: SUPPLY/DEMAND BALANCES. 10-1

List of Tables

Table		Page
1.1	Forecast of Total End Use Energy Requirements by Fuel Type	1-4
1.2	Residential Sector Energy Requirements	1-7
1.3	Commercial Sector Energy Requirements	1-11
1.4	Industrial Sector Energy Requirements	1-15
1.5	Transportation Sector Energy Requirements	1-18
1.6	Provincial Electricity Supply/Demand Balance	1-22
1.7	B.C. Hydro System Supply/Demand Balance	1-24
1.8	Marketable Natural Gas Supply/Demand Balance	1-25
1.9	Liquid Hydrocarbon Supply/Demand Balance	1-27
1.10	Hog Fuel Supply/Demand Balance	1-29
2.1	Economic Growth Assumptions	2-2
2.2	Financial Assumptions	2-3
2.3	Supply of Labour	2-4
2.4	Computation of B.C. Gross Domestic Product	2-5
2.5	Forecast of GDP by Sector	2-6
2.6	Details of Industrial GDP Forecast	2-9
2.7	Forecast of Demographic Variables	2-10
2.8	World Oil Price	2-11
2.9	Blended Crude Oil Price Forecast	2-12
2.10	Refined Petroleum Product Prices (Nominal $)	2-13
2.11	Refined Petroleum Product Prices (1982 $)	2-14
2.12	Average Natural Gas Prices (Nominal $)	follows 2-14

List of Tables
(Continued)

Table		Page
2.13	Average Natural Gas Prices (1982 $)	follows 2-14
2.14	Average Electricity Prices (Nominal $)	2-15
2.15	Average Electricity Prices (1982 $)	follows 2-15
3.1	Historical Residential Sector Energy Requirements	3-2
3.2	Heating Fuel Efficiency Assumptions	3-6
3.3	Provincial Residential Sector Energy Requirements	3-8
3.4	Provincial Residential Sector Market Shares	3-9
3.5	Mainland Residential Sector Energy Requirements	follows 3-9
3.6	Mainland Residential Sector Market Shares	follows 3-9
3.7	Vancouver Island Residential Sector Energy Requirements	follows 3-11
3.8	Vancouver Island Residential Sector Market Shares	follows 3-11
4.1	Commercial Sector GDP: 1961-1981	4-3
4.2	Historical Commercial Sector Energy Requirements	4-4
4.3	Comparison of Economic Activity with Energy Consumption in the Commercial Sector - 1979	4-6
4.4	Details of Commercial GDP Forecast	4-7
4.5	Provincial Commercial Sector Energy Requirements	4-8
4.6	Provincial Commercial Sector Market Shares	4-9
4.7	Mainland Commercial Sector Market Shares	4-10
4.8	Mainland Commercial Sector Energy Requirements	4-11
4.9	Vancouver Island Commercial Sector Market Shares	4-12
4.10	Vancouver Island Commercial Sector Energy Requirements	4-13

List of Tables
(Continued)

Table		Page
5.0.1	Economic Activity in the Industrial Sector: GDP	5-3
5.0.2	1980 Energy Consumption Profile of the Industrial Sector	5-4
5.0.3	Industrial Sector Energy Requirements	5-5
5.0.4	Provincial Industrial Sector Market Shares	5-6
5.1.1	Mill Categories for Forecasting Energy Requirements	5-12
5.1.2	1980 Pulp and Paper Energy Requirements	5-13
5.1.3	Forecast of Pulp and Paper Production	5-16
5.1.4	Forecast of Pulp and Paper Energy Requirements: Newsprint Mills	5-21
5.1.5	Forecast of Pulp and Paper Energy Requirements: S. Coast Kraft Mills	follows 5-21
5.1.6	Forecast of Pulp and Paper Energy Requirements: Lower Mainland Paper Mills	follows 5-21
5.1.7	Forecast of Pulp and Paper Energy Requirements: Interior Kraft Mills	follows 5-21
5.1.8	Forecast of Pulp and Paper Energy Requirements: N. Coast Kraft Mills	follows 5-21
5.1.9	Forecast of Pulp and Paper Energy Requirements: Province	follows 5-21
5.1.10	Forecast of Pulp and Paper Energy Requirements: Vancouver Island - Southern Route	follows 5-21
5.1.11	Wood Products Industry Historical Production	5-24
5.1.12	Wood Products Industry Energy Requirements	5-24
5.1.13	Forecast of Lumber Production	5-25
5.1.14	Forecast of Wood Products Industry Energy Requirements	5-26

List of Tables
(Continued)

Table		Page
5.2.1	Primary Metals Industry Historical Energy Requirements	5-29
5.2.2	Primary Metals Industry Energy Requirements	5-32
5.3.1	Forecast of Chemicals Industry Energy Requirements	5-35
5.4.1	Non-Metallic Minerals Industry Historical Energy Requirements	5-38
5.4.2	Non-Metallic Minerals Sector Energy Requirements	5-39
5.5.1	Petroleum Refinery Sector	5-44
5.5.2	Petroleum Refinery Sector Energy Requirements	5-45
5.6.1	Petrochemical Sector Electricity Requirements	5-48
5.7.1	1980 Profile of the Other Manufacturing Industry	5-49
5.7.2	Other Manufacturing Sector Energy Requirements	5-52
5.8.1	Mining Industry Historical Energy Requirements	5-53
5.8.2	Forecast of Mineral Production in British Columbia	5-54
5.8.3	Mining Sector Energy Requirements	5-59
5.9.1	Historical Energy Requirements for the Logging and Construction Industries	5-61
5.9.2	Other Industrial Sector Energy Requirements	follows 5-61
6.0.1	Total Transportation Energy Requirements	6-2
6.1.1	Historical Road Sector Energy Requirements	6-3
6.1.2	Fuel Efficiencies for New Passenger Vehicles	6-7
6.1.3	Road Transport Sector Energy Requirements	6-8
6.1.4	A Comparison of Forecasts of the Number of Automobiles per Person and per Household	6-10

List of Tables
(Continued)

Table		Page
6.1.5	New Car Sales and the Stock of Passenger Vehicles	6-10
6.1.6	Passenger Vehicles Energy Requirements	6-13
6.1.7	Range of Possible Payback Periods for Private New Passenger Vehicles	6-16
6.1.8	Proportion of Vehicles Using Propane or Natural Gas in the Year 2000	6-19
6.1.9	Commercial Vehicles Energy Requirements	6-22
6.2.1	Origin of Diesel Fuel Used by Railways in British Columbia	6-25
6.2.2	Rail Transport Sector Energy Requirements	6-27
6.3.1	Marine Sector Energy Requirements	6-32
6.4.1	Number of Passengers and Cost of Air Travel	6-39
6.4.2	Air Sector Energy Requirements	6-41
7.1	Forecast of Refined Petroleum Product Requirements for Non-Energy Use	7-4
7.2	Petrochemicals and Liquefied Natural Gas Sector Feedstock Requirements	follows 7-4
8.1	Provincial (End-Use) Energy Requirements by Sector	follows 8-1
8.2	Forecast of Total (End-Use) Fuel Requirements	follows 8-1
8.3	Electricity Requirements by Sector	8-2
8.4	Natural Gas End-Use Energy Requirements by Sector	8-3
8.5	Forecast of Natural Gas Requirements: Vancouver Island - Southern Route	8-4
8.6	Refined Petroleum Products (RPP) End-Use Energy Requirements by Fuel Type	8-5

List of Tables
(Continued)

Table		Page
8.7	Refined Petroleum Products Requirements by Sector	8-6
8.8	End-Use Energy Requirements of Other Energy Sources	8-7
8.9	Losses and Fuel Used by Energy Supply Industries	8-8
8.10	Primary Energy Requirements Forecast	follows 8-10
8.11	Primary Fuel Requirements	follows 8-10
9.1	Provincial Electricity Capability	9-4
9.2	Potential Hydroelectric Supply Options	9-6
9.3	Maximum Annual Producibility of Marketable Natural Gas	9-9
9.4	Annual Domestic Crude Oil Producibility	9-11
9.5	Production of Heavy Fuel Oil by Domestic Refiners	9-13
9.6	Hog Fuel Supply	9-16
10.1	Provincial Electricity Supply/Demand Balance, GWH	10-2
10.2	Provincial Electricity Supply/Demand Balance, PJ	follows 10-2
10.3	Supply/Demand Balance on the B.C. Hydro System, GWH	follows 10-2
10.4	Supply/Demand Balance on the B.C. Hydro System, PJ	10-3
10.5	Producibility Test-Project Oriented Form - Hypothetical Export or Energy Use Project	10-6
10.6	Extended Reserves Test Forecast of Total Surplus	10-9
10.7	Supply/Demand Balance for Liquid Hydrocarbons, M^3	follows 10-9

List of Tables
(Continued)

Table **Page**

10.8 Supply/Demand Balance for Liquid Hydrocarbons, PJ follows 10-9

10.9 Supply/Demand Balance for Heavy Fuel Oil, M^3 10-10

10.10 Supply/Demand Balance for Heavy Fuel Oil, PJ 10-11

10.11 Hog Fuel Supply and Demand Balance 10-12

Table of Energy Conversion Factors

Fuel Type	Conversion Factors
Coal	1 kilotonne = 29.53 terajoules
Coke	1 kilotonne = 28.83 terajoules
Petroleum Coke	1 megalitre = 42.38 terajoules
Coke Oven Gas	1 gigalitre = 18.61 terajoules
Natural Gas	1 gigalitre = 38.35 terajoules
Crude Oil	1 megalitre = 38.51 terajoules
Motor Gasoline	1 megalitre = 34.66 terajoules
Diesel Fuel Oil	1 megalitre = 38.67 terajoules
Light Fuel Oil	1 megalitre = 38.67 terajoules
Heavy Fuel Oil	1 megalitre = 41.73 terajoules
Aviation Gasoline	1 megalitre = 33.52 terajoules
Aviation Turbo Fuel	1 megalitre = 35.93 terajoules
Kerosene/Stove Oil	1 megalitre = 37.68 terajoules
Still Gas	1 megalitre = 41.73 terajoules
Gas Plant LPG's	1 megalitre = 27.18 terajoules
Refinary LPG's	1 megalitre = 27.18 terajoules
Propane	1 megalitre = 25.50 terajoules
Butane	1 megalitre = 28.60 terajoules
Hydroelectricity	1 gigawatt hour = 3.60 terajoules
Thermal Electricity	1 gigawatt hour = 3.60 terajoules
Non-Energy Products	1 megalitre = 42.06 terajoules
Hog Fuel	1 megalitre SWE* = 7.69-9.10 terajoules (*SWE = Solid Wood Equivalent)
Kilo = 10^3	1 megalitre = 1000 cubic metres
mega = 10^6	1 Btu = 1054.615 joules
giga = 10^9	1 cubic foot of gas = 1030 Btu's
tera = 10^{12}	1 barrel = 0.15891 cubic metres
peta = 10^{15}	1 gallon = 4.54609 litres
	1 cubic foot = 0.02832784 cubic metres

INTRODUCTION

This is the third energy supply/demand forecast published by the British Columbia Ministry of Energy, Mines and Petroleum Resources. The forecasting approach used by the Ministry in its previous two publications was very similiar to the forecasting methodology employed by the British Columbia Energy Commission[1] over a number of years. This earlier approach, though sound, is inordinately disaggregated and relies on a large volume of data which is not readily available from published sources. Moreover, the level of disaggregation embodied in this approach makes it difficult to assess the impact of energy price changes and fluctuations in economic growth on energy demand in the province.

In recognition of these and other inherent limitations in this approach and a growing need for a forecasting and policy planning tool, the Ministry in 1982 embarked on a project to develop an energy demand and planning model based on econometric formulations. This model is now complete and in place.[2] Further refinements and expansions of this model, however, are anticipated to take place over time.

---

[1] In 1980, the B.C. Energy Commission was restructured. With this restructuring the forecasting responsibility of the Commission was transfered to the Ministry and the Commission was renamed as B.C. Utilities Commission.

[2] Details of this model are provided in another Ministry publication: "The B.C. Energy Demand Forecasting and Planning Model"; Staff Paper, B.C. Ministry of Energy, Mines and Petroleum Resources, March 1983.

The energy forecast estimates presented in this document for the province in total were developed with the aid of this model. The model was also used with regional economic input to estimate total energy requirements for Vancouver Island. Energy demand for the residential and commercial sectors on Vancouver Island was allocated between fuels by using the results of an earlier Vancouver Island Pipeline Study[3] to provide reasonable estimates of market shares of each fuel. Consistency was maintained by applying the methodology used in the Pipeline study to the updated economic environment of the present forecast as a check. Results of the estimates applicable to the Vancouver Island market alone are highlighted in various sections of this forecast.

The report has been organized into ten chapters. Chapter 1 is an executive summary. Chapter 2 includes a discussion on key underlying assumptions. The sectoral energy forecasts (residential, commercial, industrial and transport) are then discussed in the next four chapters. Chapter 7 summarizes fuel demand for non-energy applications and Chapter 8 presents the total primary and secondary energy requirements. Next, the conventional fuel supply forecasts are discussed and finally, in Chapter 10 a discussion on energy demand and supply balance is provided.

---

[3] "Natural Gas Supply to Vancouver Island-Technical Report"; Ministry of Energy, Mines and Petroleum Resources; April, 1983.

CHAPTER 1

EXECUTIVE SUMMARY

1.0 Overview

In the time which has elapsed since the Ministry's previous forecast of British Columbia's Requirements and Supply in 1981, significant events affecting world economies and energy demands have taken place. Most notably, the rapid acceleration in world oil prices beginning in 1979 coupled with restrictive monetary policies here and in the U.S. designed to contain entrenched inflationary pressures, precipated historically high real interest rates and a consequent recession of economic activity.

For British Columbia, the world recession has resulted in a protracted downturn in the growth rates of the major sources of economic growth in the province - namely the forest and mining industries. These industries are also among the most energy intensive, accounting for almost 50 percent of the non-transportation energy requirements in the province.

The recent recessionary experience has also impinged on the long-term outlook for British Columbia's economic growth. In the seven year period between 1983 and 1990, for example, real gross provincial product is anticipated to increase at an average annual rate of only 3.3 percent compared to 5.3 percent during the decade of the 1970's. Forecast growth during the 1990's is improved to 3.7 percent per year.

In spite of this reduced growth rate, real gross provincial product will increase 80% by the year 2000 and per capita GDP will grow by 39 percent.

In backdrop to an environment of lower economic growth are assumptions of higher prices for natural gas and electricity. The outlook for refined petroleum product prices, on the other hand, is somewhat weaker than previously foreseen, reflecting a world surplus for oil brought on in part by lower world wide economic growth. Real residential light fuel oil prices, for example, are expected to be no higher in 1990 than they are today and to increase at only 0.75 percent per year during the 1990's.

With the new provincial policy to phase-in the average wholesale price for natural gas to 65 percent of the blended crude price at Vancouver City gate by 1990, it is anticipated that real natural gas prices in the residential sector, for example, will increase at average annual rates of 3.5 percent between 1981 and 1990 and 0.8 percent between 1981 and the year 2000. Natural gas, however, will continue to be cheaper than light fuel oil with the residential gas price in 1990 equal to two-thirds of the oil price in constant (1982) dollar terms.

The forecast of electricity price increases takes cognizance of indexed water rental fees and Special Direction Number One (Revised) which requires B.C. Hydro to achieve an interest coverage ratio of 1.3:1 by fiscal year 1990/91. The Special Direction originally required B.C. Hydro to reach the interest coverage ratio by fiscal 1983/84. In light of the debt loads associated with the Revelstoke Dam and the Cheekye-Dunsmuir power line to Vancouver Island, and other factors, it became clear that that the target interest coverage ratio could not be achieved in 1983/84 without substantial rate increases, and the date for achieving this ratio was moved back.

For the purposes of this forecast, it has been assumed that real electricity prices will increase at an average annual rate of 2 percent until 1990/91 and 1 percent thereafter. These assumptions are consistent with achieving the interest coverage ratio by 1990/91 and moving towards replacement cost pricing thereafter.

In light of the above factors, it is forecast that total provincial end-use energy requirements will increase at an average annual rate of 1.7 percent from 801 PJ in 1983 to 1061 PJ in the year 2000. (Table 1.1) This relatively slow growth means that the amount of energy required to create one dollar of GDP declines from 57.82 MJ in 1983 to 42.35 MJ by the year 2000. British Columbians will be able to achieve an 80% increase in GDP by using only 32% more energy than is used today.

The energy intensity of GDP has been declining during the 1970's and early 1980's in response to price induced conservation. This decline is expected to accelerate in the forecast period, partly due to continued conservation initiatives but mainly due to a swing in the mix of GDP components away from the slower growing, energy intensive industries such as forestry and pulp and paper towards the more rapidly growing but less energy intensive service sector and general manufacturing industries. A major contribution to the reduction results from improved automobile efficiency as the federal new car efficiency (Corporate Average Fuel Efficiency, CAFE) standards infuse the total automotive population. These savings are especially significant since they are all oil products and reduce British Columbia's dependence on out-of-province supplies.

In terms of the major fuel types, it is anticipated that the shares for electricity and natural gas will increase at the expense of liquid hydrocarbons whose share declines from 38.5 percent in 1983 to 34.8 percent by the year 2000.

Table 1.1

Forecast of Total End Use Energy Requirements by Fuel Type

(petajoules)

Year	Liquid Hydrocarbons[1]	Electricity[2]	Natural Gas[3]	Other[4]	Total
1981(act.)	365	136	155	172	828
1983(est.)	308	145	158	190	801
1985	301	156	163	199	819
1990	301	174	174	225	874
2000	369	219	211	262	1061
AAR					
1981-1990	- 2.1	2.8	1.3	3.0	0.6
1983-1990	-0.3	2.7	1.4	2.4	1.3
1983-2000	1.1	2.4	1.7	1.9	1.7

---

[1] Includes refined petroleum products and natural gas liquids.

[2] Includes self generated and purchased electricity.

[3] Excludes natural gas used as a feedstock.

[4] Includes hog fuel, waste liquor, coal, other by-products and renewables.

By far the fastest growing fuel is electricity with an average annual growth rate of over 2.4 percent between 1983 and the year 2000. Consequently, its share of total end-use energy rises from 18.1 percent in 1983 to 20.6 percent by the year 2000. For the most part this growth is centered in the residential sector, commercial sector, primary metals and other manufacturing industries.

Spurred in part by the commencement of service to Vancouver Island in 1986, the growth in natural gas is expected to average 1.7 percent between 1983 and the year 2000. Consequently, its share rises only from 19.7 percent in 1983 to 19.9 percent by the year 2000. By 1990, natural gas demand on Vancouver Island is expected to account for 7% of all natural gas energy, excluding non-energy uses such as petrochemical feedstock and liquefied natural gas (LNG).

The supply-demand balances for the major fuel types (natural gas, electricity, liquid hydrocarbons and hog fuel) are outlined in more detail below. In summary, it is anticipated that the next in-service date for a hydroelectric project on the B.C. Hydro system will be sometime in 1997. Further, there will be sufficient natural gas to meet all domestic and export commitments incuding 50% of the feedstocks required by a pending liquefied natural gas (LNG) project.

The province will continue to rely on extra-provincial supplies for meeting more than 75 percent of its liquid hydrocarbon requirements. Reduced production of heavy fuel oil from domestic refineries will mean heavy fuel oil imports will be needed to support growth in demand, especially for marine bunkers. Finally, there appear to be opportunities for further expansion of hog fuel utilization in the Interior and on the North Coast while the South Coast industry will be constrained by availability.

1.1 Sectoral Summary

1.1.1 Residential Sector

Residential energy in this sector is required for space and water heating and operation of household appliances and lighting in single detached and attached housing units, apartments and mobile homes. In 1981, residential energy requirements accounted for 14 percent of total end-use energy used in the province.

During the 20 year period between 1961 and 1981, residential energy requirements grew at an average annual rate of 3.4 percent from approximately 59 PJ to 117 PJ. In contrast, forecast requirements are expected to grow by only 1.7 percent annually until the year 2000. (Table 1.2) Underlying this dramatic turnaround is a downturn in the rate of growth in the housing stock from an average of 3.4 percent annually between 1961 and 1981 to an anticipated 2.1 percent between 1981 and the year 2000. Also, it is anticipated that through the forecast period, multiple dwellings, which are less energy intensive than other forms of housing, will make up a larger proportion of the total housing stock increasing from 32 percent in 1981 to 39 percent by the year 2000.

Contributing to a lower energy requirements growth rate, as well, is the impact of conservation induced by higher energy prices. In addition to price induced conservation, it has also been assumed that the average efficiency of natural gas furnaces will increase as the use of high efficiency furnaces becomes more widespread.

Table 1.2

Residential Sector Energy Requirements
(petajoules)

Year	Natural Gas	RPP	Electricity	Renewable	Total
1981	56	27	34	0	117
1985	67	20	43	0	130
1990	71	19	47	1	138
1995	73	23	51	2	149
2000	78	24	57	4	163
AAR					
1981-1990	2.7	-3.8	3.7	--	1.8
1981-2000	1.8	-0.6	2.8	--	1.7

In terms of requirements by fuel type, it is apparent from Table 1.2 that the shares of natural gas and electricity increase at the expense of refined petroleum products, RPP's. The swing away from petroleum products towards other fuels during the early eighties is a lagged response to the rapid increases in RPP prices between 1979 and 1982. Throughout the forecast period, the switch to electricity is reinforced by a trend toward multiple housing units where electricity is used for both space and water heating. Consequently, the share of electricity increases from 29 percent of total residential energy requirements in 1981 to 35 percent in the year 2000.

Natural gas requirements also increased in response to the rapid increase in RPP prices over the 1979 to 1982 period. The commencement of natural gas service to Vancouver Island in 1986 and the Canadian Off-Oil Substitution Program (COSP) give rise to a further boost in natural gas requirements. Consequently the share of natural gas rises from 48 percent in 1981 to 51 percent by 1990. However in light of a lagged response to rising natural gas prices in the 1980's relative to those of light fuel oil and the remergence of oil growth following termination of the C.O.S.P. program, the share of natural gas is expected to return to 48 percent by the year 2000.

Renewable energy, which is defined to include wood, solar and wind energy, is expected to gain some measureable acceptance as rising conventional energy prices and new technology make this form of energy more attractive. By the year 2000, it is anticipated that 4 PJ or 2.5 percent of the total provincial residential energy requirements will be met by renewable energy sources.

1.1.2 Commercial Sector

The commercial sector has been defined to include the following economic activities: finance, insurance, real estate, retail and wholesale trade, transportation and communication, private and business services, and public administration. Agriculture and construction are not included in the Commercial Sector.

Between 1971 and 1981 total commercial sector energy requirements grew at an average annual rate of about 3.0 percent compared to 11.4 percent between 1961 and 1971. The dramatically slower growth rates in the seventies were in response to slower economic growth coupled with rising real energy prices and much the same outlook is foreseen for the forecast period - particularly during the eighties where commercial sector GDP averages only 2.1 percent annually.

Commercial sector energy requirements are forecast to grow at an average annual rate of 1.9 percent between 1981 and 2000, a rate substantially lower than the 3.2 percent compound growth rate expected from the contribution of the commercial sector to gross provincial product. This implies a reduction in energy intensity of 21 percent by the year 2000 as the effect of price induced conservation in the form of improved building design, more efficient use of lighting, ventilation, air conditioning systems, etc..

In terms of the major energy types, the shares of electricity and natural gas increase at the expense of RPP's, even more dramatically than in the residential sector. The lion's share of requirements growth goes to natural gas and again this is buoyed by the commencement of natural gas service on Vancouver Island in 1986. It is expected that the share of natural gas will increase from 41 percent in 1981 to almost 46 percent in the year 2000 to reach 53 petajoules (Table 1.3). Electricity grows equally as rapidly as natural gas to increase its share from 36 percent to 40 percent during the period. Electricity and natural gas requirements are both anticipated to grow at average annual rates of 2.5 percent between 1981 and the year 2000 - some 0.6 percentage points above the average growth rate for total energy.

Oil's share declines throughout the forecast period - particularly for the period up to 1990, reflecting a continued lagged adjustment to the oil price increases in the 1979 to 1982 period and the commencement of natural gas service to Vancouver Island in 1986. By the year 2000, oil's share stands at 14.1 percent, down from 22.8 percent in 1981. Despite this decline, economic growth and relatively stable prices lead to some increase in oil requirements during the nineties.

1.1.3 Industrial Sector

The industrial sector comprises ten economic industrial components: pulp and paper, wood, primary metals, chemicals, non-metallic minerals, petroleum and coal products, petrochemicals, other manufacturing, mining and other industrial. Natural gas feedstock requirements have been identified as non-energy demand and therefore are not included in industrial sector energy requirements. Total requirements for the

Table 1.3

Commercial Sector Energy Requirements
(petajoules)

Year	Natural Gas	RPP	Electricity	Total
1981	33	19	29	81
1985	34	14	31	79
1990	39	11	34	84
1995	45	14	39	98
2000	53	16	47	116
AAR				
1981-1990	1.7	-4.9	1.7	0.5
1981-2000	2.5	-0.6	2.5	1.9

industrial sector amounted to 368 PJ in 1981, accounting for almost 45 percent of the province's total energy requirements. By the year 2000, it is anticipated that industrial sector requirements will have grown to 48 percent of the total provincial requirements. Most of this growth is centered in the mining, non-metallic and primary metals industries.

Of the ten industrial components, forest products, mining, primary metals and non-metallic mineral industries alone consumed about 87 percent of the energy used in the industrial sector. Characteristics of the future performance expected for the main energy intensive industries are summarized as follows.

The forest products industry, representing the combination of the pulp and paper and wood industries, is expected to experience a slow rate of recovery from the current recession and to reach a point in the 1990's where growth is constrained by available wood supply. As a result growth in energy requirements for this industry is low, averaging 1.4 percent per year and is impacted by the spread of thermo-mechanical and chemi-thermo-mechanical pulp technology which reduces energy requirements per unit of output but which also is electricity intensive, and the increased utilization of waste wood - particularly in the Interior of the Province.

The primary metals industry is dominated by two large firms, Cominco and Alcan, producing lead/zinc and aluminum respectively. Energy requirements are predominantly for electricity, often provided by company owned generating facilities. The industry is expected to enjoy a fairly healthy growth rate supported by the addition of a second lead/zinc smelter in the mid 1990's, a ferro-silicon smelter and a copper smelter in the early 1990's and two aluminum smelters. Energy requirements are forecast to grow at an annual average rate of 3.6 percent with electricity growth at a slightly higher 3.7 percent.

The non-metallic minerals industry is dominated by cement manufacture with the remainder of the industry comprising glass and miscellaneous non-metallic mineral product manufacture. There are three cement plants operating in the province, two employing the dry process which is less energy intensive but more electric intensive than the wet process used by the third plant. It is expected that the wet process plant will switch from natural gas to coal to supply most of its energy requirements. Energy requirements growth depends on growth of the domestic construction industry and modest increases in cement exports to the U.S. Total energy is forecast to grow at an annual average rate of 2.5 percent over the period while electricity grows at 4.5 percent.

The mining industry in British columbia is comprised of a host of open-pit and underground operations producing coal, copper, lead, zinc, molybdenum, gold, silver and other metallic and non-metallic minerals, with large scale coal and copper open-pit operations dominating. The forecast assumes that only one new major copper mining property will be developed in the province by the turn of the century. A new lead/zinc operation is assumed to be developed by the late 1980's. Coal production is forecast to grow rapidly with thermal coal production expected to increase from less than 1 million tonnes in 1981 to 8 million tonnes by the year 2000 and metallurgical coal expanding from 11 million tonnes to 21 million tonnes.

Metal mines are relatively energy intensive operations using primarily electricity and diesel fuel. Coal mines have used large quantities of natural gas for coal drying. Total energy requirements are forecast to grow at an average annual rate of 2.7 percent during the period with refined petroleum products, essentially diesel fuel, growing at 4.3 percent per year. The use of natural gas is expected to decline over time as refuse coal is substituted for coal drying operations.

When energy requirements for these energy intensive industries are added to the energy demands of the rest of the industrial sector, total industrial energy is forecast to grow at an annual average rate of 1.7 percent as indicated on Table 1.4. The major energy type used in the industrial sector is waste material in the form of hog fuel and pulping liquor which is consumed in the forest products subsector. These waste materials account for 46 percent of the total energy consumed in the industrial sector and about 21 percent of all energy consumed in the province. It is expected that requirements for these materials will grow at an average annual rate of 1.8 percent between 1981 and the year 2000.

The second largest form of energy utilized in the industrial sector is electricity (purchased and self-generated) followed by natural gas. It is expected that total electricity requirements will grow at an average annual rate of 2.3 percent between 1981 and the year 2000. Natural gas requirements, on the other hand, grow at only 0.4 percent reflecting displacement in the mining and non-metallic minerals sectors by coal, displacement in the interior forest industry by hog fuels and pulping liquors and relatively higher natural gas prices overall. Increased requirements arising out of the commencement of service to Vancouver Island only partly offset the displacement on the mainland.

Table 1.4

Industrial Sector Energy Requirements

(petajoules)

Year	Natural Gas	Coal	RPP's	Hog Fuel & Pulping Liq.	Purchased Elec.	Self-Gen. Elec.	Total
1981	66	0	57	171	45	29	368
1985	62	4	59	195	52	29	401
1990	61	13	54	211	53	41	433
1995	66	15	62	228	60	41	472
2000	70	17	67	240	66	49	509
AAR							
1981-1990	-0.9	—	-0.7	2.4	1.9	4.0	1.8
1981-2000	0.4	—	0.7	1.8	2.1	2.9	1.7

A decline in heavy fuel oil demand, resulting from displacement by natural gas on Vancouver Island is masked by strong growth of diesel in the mining industry when both the products are included under the one category of refined petroleum products (RPP's).

In short, the forecast for the industrial sector indicates a long term trend away from the fossil based fuels such as natural gas and refined petroleum products toward waste material, electricity and coal. In part this is brought about through a change in industrial structure by a shift away from growth in the forest industry to growth in the metal and mineral resources in the province which utilize technologies that are less fossil fuel intensive. As well, higher relative prices for natural gas and refined petroleum products encourage substitution for other fuel types such as hog fuel, pulping liquors and coal.

1.1.4 Transportation Sector

Transportation sector energy requirements encompass those of the four modes of transportation - road, rail, marine and air. In total, transportation requirements account for about 32 percent of the energy used in the province with virtually all being in the form of refined petroleum products. Among the major fuels are motor gasoline, aviation turbine fuel, heavy fuel oil and diesel fuel. During the forecast period it is expected that propane, natural gas and electricity will play increasingly larger roles.

The dramatic increases in refined petroleum product prices since 1978 combined with the recent economic recession are expected to continue to have a depressing affect on product demand over 1981 volumes until the early nineties - especially for motor gasoline where requirements fall by an average annual rate of 2.9 percent between 1981 and 1990.

Among the important factors contributing to lower motor gasoline requirements is a trend toward smaller more fuel efficient cars brought on by rising gasoline prices. In real terms, motor gasoline prices increased at an average annual rate of 8.3 percent between 1978 and 1981 and adjustment to these higher prices is not yet complete. As well, it has been assumed that fuel efficiency will improve by an average of 2 percent per year so that by 1990 the average new car will use only 60 percent of the fuel per kilometre consumed by its counterpart in 1978.

Table 1.5 indicates that motor gasoline requirements are expected to fall from 152 PJ in 1981 to 116 PJ in 1990. Requirements begin to increase through the 1990's, reflecting the growth in the stock of commercial vehicles and the absence of further improvements to fuel efficiencies. Holding this resurgence in check is, however, an increased utilization of natural gas and propane as alternative fuels to motor gasoline. By the year 2000, it is anticipated that these two fuels will account for some 5 percent of the total road requirements.

Requirements for diesel fuel, which stem from the operation of heavy trucks, automobiles, marine carriers in coastal shipping and locomotive services, are expected to experience fairly rapid growth, averaging 1.7 percent between 1981 and the year 2000. Road requirements accounted for approximately 54 percent

Table 1.5

Transportation Sector Energy Requirements

(petajoules)

Year	Natural Gas/ Propane	Heavy Fuel Oil	Diesel Fuel Oil	Motor Gasoline	Aviation[1]	Electricity	Total
1981	0	30	54	152	26	0.2	262.2
1985	2	5	51	130	20	0.3	208.3
1990	6	20	57	116	21	0.5	220.5
1995	9	24	67	118	23	0.5	241.5
2000	14	28	74	131	26	0.6	273.6
AAR							
1981-1990	33.1	-4.4	0.7	-2.9	-2.1	12.5	-1.9
1981-2000	20.2	-0.4	1.7	-0.8	0.0	6.5	0.2

---

[1] Includes aviation gasoline.

of the diesel fuel used in the transportation sector in 1981 and while moderate growth is expected from this source it is not as strong as previously anticipated because of higher diesel fuel prices and consequently lower capture rates in automobiles.

Heavy fuel oil in the transportation sector is used exclusively in the marine bunker market. A large volume business was developed in the past by capturing an increasing share of fuel for international shipping visiting West Coast ports. This business has been curtailed by a variety of factors including; the availability of cheaper bunker fuel at U.S. ports; increased crude costs; more attractive alternative markets and lower netbacks for refiners. The demand for marine bunker fuel will grow with expanding exports of grain, coal and other bulk commodities and it has been assumed that netbacks will recover to traditional levels.

It is anticipated that requirements for aviation turbine fuel will decline until the late eighties due to the lagged response to the dramatic increases in the price of the fuel between 1978 and 1982. Through this period, airlines are expected to upgrade their fleets to more fuel efficient carriers, better align the volume of air traffic with the type of aircraft used and rationalize their routes. With improved economic growth in the nineties and an increasing demand for air transport, requirements are once again expected to increase to levels experienced in the recent past.

Electricity is expected to make modest inroads in the transportation sector during the eighties and nineties. In addition to the existing trolley bus system in Vancouver which uses electric motors for propulsion, allowance has also been made for the requirements of the Automated Light Rapid Transit (ALRT) system which is currently under construction and assumed to begin service in 1986. As well, it is expected that B.C. Rail will begin operation of an electrified branch line between Anzac and Prince George in 1984. In light of these developments, electricity requirements in the transportation sector are anticipated to increase at an average annual rate of 6.5 percent from 1981 to the year 2000.

1.2 Petrochemical Feedstocks

Feedstocks to the petrochemical industry are treated as non-energy use and as such have not been included in the above summary. For the purpose of this forecast liquefied natural gas (LNG) feedstock requirements have also been included in petrochemicals.

Petrochemical natural gas feedstock requirements are forecast to grow from 6 PJ in 1982 to 119 PJ in 1990 and 124 PJ by the year 2000. This forecast provides for growth in existing petrochemical facilities, supply of 50 percent of the feedstock requirements of a proposed liquefied natural gas (LNG) plant and a new ammonia/urea facility assumed to start up in 1987.

1.3 Fuels Summary

1.3.1 Electricity

For the most part, electricity in the province is generated from the hydroelectric facilities of four large producers that include B.C. Hydro, West Kootenay Power and Light (WKPL), Cominco and Alcan. The forestry industry also generates small amounts of electricity - mostly by thermal means but this is largely consumed within the industry.

B.C. Hydro is by far the largest supplier of hydroelectricity in the province and except for the special case of Alcan's Kemano Completion project, is assumed to develop all grid-connected major hydroelectric sites in the future.

Provincial requirements, as presented in Table 1.6, include not only sales of purchased electricity but also losses in transmission and distribution, utility own-use, and requirements met by self-generated hydro electricity in the industrial sector.[4] Supply figures, on the other hand, include all existing and committed projects (including Revelstoke) under critical water conditions on the B.C. Hydro system as well as firm supply capability from Alcan, Cominco, WKPL and industrial sources.

Projects which require Energy Project Certificates such as Site C, Keenleyside, Murphy Creek, and Kemano Completion have not

---

[4] These have been included for comparability to the supply figures which include self generation - Alcan, Cominco, etc. and total provincial supply figures in Chapter 9.

Table 1.6

Provincial Electricity Supply/Demand Balance
(GWH)

Year	Total Provincial Requirements	Total Firm Provincial Supply	Supply/Demand Balance (deficit)
1983	44,648	50,795	6,147
1985	47,973	59,320	11,348
1990	53,445	59,320	5,876
1991	54,323	59,320	4,998
1992	55,289	59,320	4,031
1993	56,314	59,475	3,162
1994	57,496	59,475	1,979
1995	58,444	59,475	1,031
1996	59,431	59,475	45
1997	61,190	59,475	(1,714)
2000	67,157	59,475	(7,681)
AAR			
1983-2000	2.4	--	--

been included in the provincial supply estimates.[5] Table 1.6 indicates, in total, that with requirements growing at an average annual rate of 2.4 percent between 1983 and the year 2000 new generation facilities will be required some time in 1997. Since it has been assumed that B.C. Hydro will develop all major new grid-connected hydroelectric sites, a similar picture emerges when the B.C. Hydro is examined in isolation, as reported in Table 1.7.

1.3.2 Natural Gas

A forecast of the maximum producibility of natural gas from fields in British Columbia combined with firm contracted extra-provincial supplies indicates that total supply is capable of meeting forecast domestic and export requirements on an annual basis over the entire forecast period. (Table 1.8)

The supply forecast is based on an assumption that exploration activity will improve to the extent that gas wells drilled in the province will increase from 50 in 1983 to 100 in 1984, 200 in 1985, 300 in 1986 and thereafter. The total supply of natural gas to the province is expected to decline, however, from 13.9 billion cubic metres in 1984 to about 13.7 billion cubic metres in the year 2000, reflecting primarily the decline of contracted extra-provincial supplies. Requirements for this producibility balance include total authorized exports even though export sales are expected to be much less than authorized.

---

[5] This convention results in an asymetrical treatment of More Creek and the Kemano Completion. The forecast of self generated electricity requirements in the mining sector includes Kemano Completion and More Creek whereas the supply figures in Table 1.6, exclude these facilities. If More Creek did not proceed, electricity could be provided through alternate sources, e.g. diesel or coal thermal sources.

Table 1.7

B.C. Hydro System Supply/Demand Balance (GWH)

Year	Requirements[1]	Firm Capability	Supply/Demand Balance (deficit)
1983	33,834	38,795	4,961
1985	37,159	47,320	10,161
1990	40,256	47,320	7,065
1991	41,134	47,320	6,186
1992	42,100	47,320	5,220
1993	43,125	47,475	4,351
1994	44,307	47,475	3,168
1995	45,256	47,475	2,220
1996	46,242	47,475	1,233
1997	48,006	47,475	(531)
2000	52,073	47,775	(4,598)
AAR			
1983-2000	2.6	--	--

---

[1] Includes WKPL deficit, and purchased electricity requirements only.

Table 1.8

Marketable Natural Gas Producibility Balance

(billions cubic metres)

Year	Maximum Producibility[1]	Total Requirements[2]	Supply/Demand Balance
1984	13.9	14.0	(0.1)
1985	13.9	13.7	0.2
1990	12.8	12.5	0.3
1995	14.1	14.0	0.1
2000	13.7	13.7	0.0

---

[1] Includes extra-provincial supplies.

[2] Includes forecast of total authorized export requirements plus allocation of gas to LNG, ammonia/urea and extended pipeline exports beyond 1992.

In 1982, a Commissioner Inquiry[6] developed a set of criteria for determining the existence and extent of a natural gas surplus and the estimation of the volumes of natural gas which could reasonably be allocated to export. The Report stressed the importance of markets in promoting exploration activity in the province. Based on the findings of the Inquiry, the province allocated 400 Bcf of natural gas reserves to an ammonia/ urea project, 800 Bcf to a liquefied natural gas (LNG) project and 1800 Bcf to continuation of pipeline exports in the 1990's.

Since the initial allocation of the surplus, the realized surplus at the beginning of 1984 exceeds what had been projected. A number of factors contributed to this, including an increase in reserves, gas exports below authorized volumes for 1982 and 1983, and lower than forecast requirements for the mining and pulp and paper sectors. Revised estimates of the natural gas surplus indicated that the surplus could support an additional 25 percent commitment to the LNG project and government has subsequently increased the total commitment to 50 percent or 1600 BCF.

1.3.3 Liquid Hydrocarbons

The province is expected to continue to rely heavily on extra-provincial supplies to meet requirements for liquid hydrocarbons as indicated in Table 1.9. While B.C. refineries have the capacity to supply all provincial requirements, less than 25 percent of their crude oil and natural gas liquids feedstocks are produced from B.C. oil fields. The remainder originates in Alberta. The contribution by B.C. oil fields is expected to

---

[6] "Commissioner Inquiry on British Columbia's Requirements, Supply and Surplus of Natural Gas and Natural Gas Liquids," George W. Govier, Commissioner, Victoria, May, 1982.

Table 1.9

Liquid Hydrocarbon Supply/Demand Balance

(000 cubic metres)

Year	Total Requirements	Total Supply	Supply/Demand Balance (deficit)
1981	11,397.4	2,208.8	(9,188.6)
1985	10,243.7	2,282.9	(7,960.7)
1990	10,493.1	1,988.6	(8,504.5)
1995	11,654.3	2,075.0	(9,579.3)
2000	13,418.6	2,217.8	(11,200.8)
AAR			
1981-2000	0.3	- 0.2	--

decline to 21 percent by the year 2000 as a growth in requirements, centred primarily in the requirements for diesel and heavy fuel oil is met by only a slight increase in domestic production.

Heavy fuel oil (HFO) is of special interest primarily because of its potential to displace natural gas as an industrial fuel, especially on Vancouver Island. Since HFO is a residual product, its output is largely determined by the total throughput of crude oil in refineries needed to produce light oil requirements. It is anticipated that the yield of HFO will be reduced to around 9 percent of refinery throughput as a result of residual oil upgrading facilities presently being installed. this reduced yield combined with lower levels of crude oil throughput resulting from lower light oil requirements is expected to drop the production of HFO to levels from 10 to 25 percent below production rates in the recent past.

The reduced HFO production coupled with rising HFO demands, particularly for marine bunkers is forecast to create a short bunker position which will likely result in reestablishment of interprovincial transfers of bunker from Alberta.

1.3.4 Hog Fuel

Hog fuel supplies are determined by volume of bark associated with the forecast of timber production and supply exceeds requirements at the provincial level, as shown in Table 1.10. On a regional basis, however, hog fuel utilization on the South Coast will be restricted by available supplies beyond 1996. In contrast, supplies are more than adequate to meet forecast requirements in the Interior over the entire forecast period and indicate a great potential for displacing natural gas.

Table 1.10

Hog Fuel Supply/Demand Balance

(petajoules)

Year	Total Provincial Requirements	Total Provincial Supplies	Supply/Demand Balance (deficit)
1981	64	158	94
1985	82	188	106
1990	92	181	89
1995	102	189	87
2000	106	187	81
AAR			
1981-2000	2.7	0.9	

CHAPTER 2

EXOGENOUS VARIABLES

2.0 Introduction

There are two major sets of exogenous variables - economic/ demographic and energy prices - which must be specified before an energy demand forecast can be prepared. This chapter presents a discussion of the underlying exogenous variable assumptions. It should be noted that there are no explicit feedbacks between the energy and economic forecasts. The economic forecast is not directly affected by the derived energy demand forecast, although there is a general consistency between the two forecasts.

2.1 Economic and Demographic Variables

The long-term economic projections underlying this energy forecast were prepared under the auspices of the Ministry of Finance in February 1984 and do not incorporate economic changes which have occurred since that time. These include disruption in the British Columbia pulp and paper industry, stronger-than-expected growth in the United States during the first half of 1984 and the resulting effect on both interest rates and the U.S.-Canadian exchange rate. June 1984 revisions to historical GDP data for British Columbia and historical GNP data for Canada are also not included. Consequently, this forecast should be viewed as a projection of recovery under conditions as they were foreseen in February 1984 and not a reflection of the Government's current view. Moreover, the long term forecast represents a basis for planning, based on expectations about long-term growth, rather than an official forecast for budgetary purposes.

External trade plays a vital role in the B.C. economy and assumptions about the economies of British Columbia's major trading partners are necessary to set the external environment in which the B.C. economy will function in the future. Forecasts of economic growth for the United States, Japan, Canada and British Columbia are presented in Table 2.1. For the purpose of formulating the long-term planning scenario it has been assumed that economic policy of the U.S. government is to contain inflation at lower rates by controlling money supply growth with high real interest rates, while at the same time accommodating moderately strong economic growth.

GNP growth in the U.S. is assumed to accelerate more slowly in the short-term than normally experienced during a typical recovery. Even so, over the medium-term, it puts upward pressure on prices which increase at more than 5.0 percent per year in 1985 and 1986. Persistent high real interest rates, however, dampen inflation over the longer-term to 3.0 - 3.5 percent range. With the containment of inflation, confidence in the U.S. economy strengthens as the economy grows at an average annual rate of 2.9 percent in the 1991 to 2000 period.

The U.S. Federal Government deficit position is assumed to exist until the early 1990's contributing somewhat to higher real interest rates. Canadian interest rates, as can be seen in Table 2.2, are projected to closely track those in the U.S. yet remain higher in most years in an environment of slightly higher inflation. Canadian economic growth will fluctuate in response to changing interest rates and the business cycles in the U.S.

In the long-run, Canada's gradually improving trade balance and favourable terms of trade are expected to strengthen the Canadian dollar to 87¢ (U.S.) by the end of the forecast period.

Table 2.1

Economic Growth Assumptions
(Annual Percentage Changes)

	United States	Canada	Japan	British Columbia
Year	(Real GNP)			(Real GDP)
1982	-1.9	-4.8	2.7	-7.0
1983	3.3	3.0	2.9	2.0
1984	4.5	4.0	4.0	3.0
1985	3.3	3.7	3.5	4.0
1986	2.5	1.5	3.0	1.5
1987	3.0	2.5	4.0	2.5
1988	4.0	3.5	5.0	4.0
1989	3.5	3.5	5.5	4.2
1990	2.5	2.5	4.0	3.7
1991	2.5	3.0	3.5	3.8
1992	3.5	4.0	4.0	3.9
1993	3.5	4.0	4.0	4.1
1994	3.0	3.5	4.0	4.0
1995	3.0	3.5	4.0	3.9
1996	2.8	3.5	3.5	3.8
1997	2.8	3.5	3.5	3.6
1998	2.5	3.0	3.5	3.5
1999	2.5	3.0	3.0	3.5
2000	2.5	3.0	3.0	3.3

Real economic growth in the U.S. is expected to moderate in the second half of 1984 and to weaken further in 1985 and 1986. Recovery is foreseen in the 1986 to 1988 period after which growth cycles moderate before settling down to 2.5 percent between 1998 and 2000. U.S. residential construction will oscillate, responding to real interest rate movements.

The economies of Japan and our other major trading partners are projected to follow the U.S. business cycle and long-term trend. Japan's growth will fluctuate less and remain stronger throughout the forecast period.

The forecast of economic activity in British Columbia was prepared following the analysis of two separate aspects of economic growth in B.C. The first approach examines population growth, labour supply and labour productivity, while the second examines industrial growth based on the future demand for goods and services produced in B.C.. The results of the two analyses are examined, compared and melded to produce the final forecast.

Table 2.3 summarizes the forecast of B.C. population and available labour force. Net interprovincial migration is assumed to be slightly below historical levels until the early 1990's when it is anticipated B.C. will enjoy relatively stronger growth compared to the rest of Canada.[1]

---

[1] Net interprovincial migration into B.C. averaged about 20 thousand people annually during the 1960's, 18 thousand during the 1970's and reached a peak of about 40 thousand in 1980. The higher levels assumed for the 1990's reflect a higher population base from which to draw migrants, and the almost uninterrupted superior performance of the B.C. economy relative to the rest of Canada.

Table 2.2

Financial Assumptions

Year	United States		Canada	British Columbia	Canada/U.S. Exchange Rate
	GNP Price Deflator (% change)	Bank Prime Interest Rate (percent)	Bank Prime Interest Rate (percent)	Vancouver CPI (% Change)	(U.S.¢/Can.$)
1982	6.1	14.7	14.0	10.5	81.0
1983	4.2	10.8	11.2	5.5	81.1
1984	4.5	11.0	11.0	4.5	80.0
1985	5.0	12.0	12.0	4.5	80.0
1986	5.5	11.0	11.5	5.0	80.5
1987	5.0	11.5	12.0	5.5	80.5
1988	4.5	10.0	10.5	5.0	81.0
1989	5.0	9.5	10.0	4.5	81.5
1990	4.0	9.0	9.5	4.5	82.0
1991	4.0	8.5	9.0	4.0	82.5
1992	4.0	8.0	9.0	4.0	83.0
1993	4.0	7.5	8.0	4.0	83.5
1994	4.0	7.0	7.5	4.0	84.0
1995	3.5	6.5	7.0	4.0	84.5
1996	3.5	6.0	7.0	3.5	85.0
1997	3.5	6.0	6.5	3.0	85.5
1998	3.5	6.0	6.5	3.0	86.0
1999	3.5	6.0	6.5	3.0	86.5
2000	3.0	5.5	6.0	3.0	87.0

Table 2.3

Supply of Labour
(in thousands)

	Net Migration			Population	Non-Inst. Population	Participation Rate	Labour Force
	Inter-Provincial	Inter-National	Total	15+	15+	(percent)	
1981	20.5	16.4	2743.8	2155.9	2092.0	65.1	1361.0
1982	0.8	13.0	2791.8	2201.2	2132.0	64.3	1370.0
1983	11.1	7.6	2830.8	2238.4	2165.0	64.2	1389.0
1984	12.0	9.4	2872.8	2276.8	2202.1	64.3	1416.0
1985	15.0	10.4	2918.5	2317.2	2241.3	65.0	1456.8
1986	12.0	11.2	2965.8	2357.3	2280.0	64.8	1477.4
1987	11.0	11.0	3011.7	2393.8	2315.3	65.2	1509.6
1988	14.0	10.0	3057.4	2428.2	2348.6	65.5	1538.3
1989	16.0	10.0	3107.6	2463.2	2382.5	65.9	1570.0
1990	16.0	10.5	3152.5	2499.2	2417.3	66.3	1602.6
1991	17.0	11.0	3200.4	2535.5	2452.3	66.6	1633.2
1992	19.0	11.5	3248.9	2572.5	2488.1	66.9	1664.5
1993	21.0	12.0	3298.6	2611.2	2525.6	67.3	1699.7
1994	22.0	12.5	3349.5	2652.0	2565.0	67.7	1736.5
1995	23.0	13.0	3400.8	2694.5	2606.1	68.1	1774.8
1996	24.0	13.5	3452.7	2738.8	2649.0	68.5	1814.5
1997	26.0	14.0	3505.6	2784.9	2693.6	68.8	1853.2
1998	28.0	14.5	3560.3	2833.3	2740.4	69.1	1893.6
1999	30.0	15.0	3616.8	2884.9	2790.3	69.4	1936.5
2000	33.0	15.5	3675.9	2939.8	2843.4	69.6	1979.0

The analysis of the fertility and mortality characteristics of the population, along with projected migration flows, provide the basis for preparing the projection of population. Provincial population is forecast to increase from 2.74 million in 1981 to 3.15 million in 1990 and 3.68 million in 2000, at average annual growth rates of 1.6 percent during the 1980's and 1.5 percent during the 1990's.

The population forecast was prepared using a cohort survival model which generates an age/sex profile of the population annually. This profile provides the forecast of population for ages 15 and over (population eligible for entry into the labour force) and the age/sex profile has also been employed to transform dynamic age/sex specific assumptions about labour force participation and productivity into forecasts of total labour force and average labour productivity presented herein. In summary, there is a maturing of the age profile of the population as the "baby boom" generation "bulge" passes into older age categories. The non-institutional population over the age of 15 is forecast to increase 1.6 percent annually between 1981 and 1990, and also between 1990 and 2000.

Based on an examination of labour force participation rates by age and sex, it was assumed that female rates will approach male rates asymptotically in corresponding age cohorts after allowing for the effect of child bearing on female participation rates in some age groups. The long-term trend is for rising average male and female participation rates as the "baby boom" population ages into cohorts characterized by higher participation rates. The labour force participation rate increases from 65.1 percent in 1981 to 69.6 percent by the year 2000 and rises more slowly during periods of high cyclical unemployment.

The total labour force is forecast to increase from 1.36 million in 1981 to 1.60 million in 1990 and to 1.98 million in 2000 giving an average annual growth rate of 1.8 percent during the 1980's and 2.1 percent during the 1990's.

Table 2.4 summarizes the assumptions regarding the unemployment rate, employment, hours worked, productivity and the resulting forecast of gross domestic product (GDP)[2].

The unemployment rate is expected to remain at levels which are high by historical standards throughout the 1980's, reflecting constrained employment opportunities associated with the protracted recovery and cyclical downturn in 1986, combined with labour force increases of about 2.1 percent per year between 1984 and 1989. In the 1990's, the unemployment rate is forecast to decline significantly due to stronger job creation to 5.8 percent by the year 2000.

The average number of hours worked is projected to decline modestly over the forecast period, continuing a long historic trend and in response to the health of the economy.

Increases in labour productivity (measured as GDP per man-hour employed) are projected to average only 0.8 percent per year between 1983 and 1987 reflecting low growth in capacity utilization. In the 1990 to 2000 period, labour productivity is assumed to increase at an average annual rate of 1.2 percent. The major factors contributing to this productivity growth are expected to be capital formation, resource allocation, knowledge, decline in dependence on high cost energy, and economies of scale. The net effect of economic cycles on labour productivity in the long-run should be minimal.

---

[2] Gross domestic product is defined to be at factor cost in 1971 constant dollars.

Table 2.4

Computation of B.C. Gross Domestic Product

	Labour Force (thousands)	Unemployment Rate (percent)	Employment (thousands)	Work Week (hours)	Productivity (1971 Dollars)	GDP (millions of) (1971 Dollars)
1981	1361.0	6.7	1269.8	33.1	347.5	14,611
1982	1370.0	12.1	1204.2	33.5	337.5	13,595
1983	1389.0	13.8	1197.3	33.5	345.1	13,862
1984	1416.0	13.6	1223.4	33.6	347.9	14,279
1985	1456.8	13.3	1263.1	33.5	350.9	14,852
1986	1477.4	13.5	1278.0	33.4	352.7	15,076
1987	1509.6	13.1	1311.8	33.4	353.0	15,449
1988	1538.3	12.4	1347.6	33.3	357.9	16,067
1989	1570.0	11.4	1391.1	33.3	361.7	16,737
1990	1602.6	10.7	1431.2	33.2	365.2	17,360
1991	1633.2	10.0	1469.9	33.2	369.6	18,013
1992	1664.5	9.2	1511.4	33.1	374.3	18,722
1993	1699.7	8.6	1553.5	33.0	379.7	19,487
1994	1736.5	8.0	1597.6	33.0	385.0	20,274
1995	1774.8	7.6	1639.9	32.9	390.3	21,058
1996	1814.5	7.2	1683.9	32.8	395.2	21,852
1997	1853.2	6.7	1729.0	32.8	399.7	22,647
1998	1893.6	6.3	1774.3	32.7	403.8	23,434
1999	1936.5	6.0	1820.3	32.6	408.0	24,246
2000	1979.0	5.8	1864.2	32.6	412.2	25,035

The forecast of gross domestic product by this approach is obtained by multiplying the employed labour force by the average weekly hours and productivity index which are presented in Table 2.4.

The second approach involves forecasting growth at a sectoral level based on the expected demand for goods and services and subject to likely resource constraints. Table 2.5 summarizes the final forecast and it should be noted that the forecast of real gross domestic product in Tables 2.4 and 2.5 are the same and reflect the consistent methodology of the forecast preparation.

Overall, economic growth is forecast to average 1.9 percent per year between 1981 and 1990 with the primary and manufacturing industries expected to increase at average annual rates of 2.2 percent and 1.4 percent respectively. Consequently, the share of GDP represented by the manufacturing industries declines from about 17.6 percent in 1981 to 16.7 percent in 1990. The construction and utility sectors are forecast to grow at 0.8 and 2.5 percent respectively, while the commercial sector[3] grows marginally slower at 2.2 percent.

---

[3] The commercial sector is defined herein to include the following sectors: Transport, Communication and Storage; Wholesale and Retail Trade; Finance, Insurance and Real Estate; Community, Personal and Business Services; and Public Administration. In contrast to the Standard Industrial Classifications, Utilities have been excluded because their energy requirements are not included with those of the "commercial sector" as defined above. Rather requirements for utilities are included in "own-use" categories discussed more fully in Chapter 8.

TABLE 2.5

FORECAST OF GDP BY SECTOR

(MILLIONS OF 1971 DOLLARS)

YEAR	AGRICULTURE	FISHING + TRAPPING	PRIMARY FORESTRY	MINING	MANUFACT.	CONSTR'N	UTILITY	COMMERCIAL	TOTAL
1978	171	43	298	273	2,175	876	555	8,456	12,847
1979	207	42	251	332	2,358	958	538	8,864	13,550
1980	233	36	394	329	2,549	1,095	493	9,179	14,308
1981	183	28	357	378	2,572	1,292	530	9,271	14,611
1982	183	30	314	356	2,282	1,162	525	8,741	13,595
1983	187	30	377	361	2,404	1,157	520	8,828	13,862
1984	194	31	396	387	2,507	1,186	540	9,039	14,279
1985	202	31	408	405	2,616	1,257	556	9,377	14,852
1986	208	34	396	401	2,602	1,244	568	9,623	15,076
1987	212	38	404	406	2,661	1,244	591	9,893	15,449
1988	218	40	418	422	2,765	1,294	614	10,296	16,067
1989	225	43	426	438	2,838	1,359	640	10,768	16,737
1990	232	44	426	447	2,908	1,393	659	11,251	17,360
1991	239	45	430	457	3,001	1,434	682	11,725	18,013
1992	246	46	439	472	3,099	1,492	706	12,222	18,722
1993	253	47	448	488	3,203	1,551	731	12,765	19,487
1994	261	47	457	505	3,312	1,606	756	13,331	20,274
1995	269	48	466	523	3,422	1,662	779	13,889	21,058
1996	275	48	470	541	3,510	1,720	804	14,482	21,852
1997	282	49	475	558	3,600	1,772	830	15,082	22,647
1998	289	49	480	575	3,691	1,825	853	15,672	23,434
1999	297	49	482	592	3,775	1,880	876	16,295	24,246
2000	303	49	482	608	3,847	1,927	899	16,921	25,035
					ANNUAL GROWTH RATES				
1981-1990	2.66	5.22	1.98	1.89	1.37	.84	2.45	2.17	1.93
1990-2000	2.70	1.10	1.25	3.11	2.84	3.30	3.15	4.17	3.73
1981-2000	2.68	3.03	1.60	2.53	2.14	2.13	2.82	3.22	2.87

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

Economic activity in the commercial sector, as reported in Table 2.5, is forecast to grow at an annual rate of 2.2 percent between 1981 and 1990, and at 4.2 percent between 1990 and 2000. This sector consists of a number of components which display different growth patterns. Community, business and personal services is forecast to grow the most rapidly at 3.8 percent between 1981 and 2000, while public administration grows the least rapidly at 1.9 percent. The three other components grow at average rates of between 2.9 and 3.2 percent between 1981 and 2000. The commercial sector is expected to be characterized by significantly increasing productivity through greater use of computers and other information processing technologies.

This important secular shift from the goods producing to the service producing industry is expected to continue into the next decade as the share of primary and manufacturing industries declines to 21 percent by 2000 from 23 percent in 1990 and the share of commercial activity climbs from 65 percent to 68 percent of GDP. The aggregate economic growth rate is forecast to average about 3.7 percent during the 1990's and is led strongly by the increasing size and productivity of the commercial sector.

The agriculture and fishing and trapping industries together are forecast to grow at an average annual rate of 2.7 percent so that by the year 2000, their contribution to GDP is the same as in 1981 at 1.4 percent.

The primary forestry (logging) sector is projected to experience restricted growth in the 1990's, as forestry resources become fully utilized. Modest increases are expected however, in the late 1990's and are attributable to marginally more efficient harvesting techniques employed by the industry.

Table 2.6 presents details of the activity forecast for the industrial sector alone. In the mining sector, coal is expected to increase more rapidly than other components. The Northeast Coal development is expected to increase coal production sharply during the mid 1980's, and the associated placement of infrastructure will enable British Columbia to provide coal to meet the increasing demand among Pacific Rim countries. While competition for these markets from Australia, the U.S. and South Africa is expected to be strong, it is forecast that GDP attributable to coal mining will increase from 69 million (1971) dollars in 1981 to 174 million (1971) dollars by the year 2000, at an average annual rate of 5 percent. Metal mining is forecast to increase at an annual average rate of 1.7 percent between 1981 and 2000, while non-metal minerals and mineral fuels are forecast to average 2.2 percent per year.

The wood and pulp and paper industries are expected to experience growth rates of around 1.7 percent between 1981 and 1990, undergoing a modest downturn in 1985/86 period, attributable principally to conditions in the United States. Over the longer period, growth is expected to be constrained as available forest resources become fully utilized and there are insufficient supplies of fibre on which to base further expansion. The implementation of new technologies, most notably high efficiency pulp, and utilization of previously uneconomic forest stands will soften the impact of the resource constraint.

The forecast for primary metals activity assumes that a number of new projects, which are outlined fully in Section 5.2, will come on stream during the period. As a consequence, an annual increase in the contribution to GDP of 1.8 percent between 1981 and 2000 is forecast.

TABLE 2.6

DETAILS OF INDUSTRIAL GDP FORECAST

(MILLIONS OF 1971 DOLLARS)

	PRIMARY	MINING			MANUFACTURING						TOTAL
YEAR	FORESTRY	METALLIC	COAL	OTHER	WOOD	PAPER	PRI, MTL,	FOOD, BEV,	OTHER	CONSTR'N	INDUSTRIAL
1978	298	164		108	619	396	137	245	778	876	3,621
1979	251	178		153	627	439	150	265	877	958	3,898
1980	394	186		138	629	462	174	296	988	1,095	4,362
1981	357	234	69	75	594	368	179	342	1,089	1,292	4,599
1982	314	216	69	71	532	356	143	308	944	1,162	4,115
1983	377	217	69	75	638	384	142	305	934	1,157	4,299
1984	396	220	90	77	663	400	152	313	979	1,186	4,476
1985	408	227	99	80	683	404	164	329	1,037	1,257	4,687
1986	396	219	103	79	649	396	167	336	1,055	1,244	4,643
1987	404	219	107	81	662	404	169	342	1,085	1,244	4,715
1988	418	228	111	83	689	416	177	353	1,132	1,294	4,899
1989	426	237	115	86	689	424	184	365	1,176	1,359	5,061
1990	426	241	118	88	689	433	190	376	1,222	1,393	5,175
1991	430	246	120	90	702	441	196	387	1,275	1,434	5,323
1992	439	253	125	93	709	454	201	399	1,336	1,492	5,502
1993	448	261	130	97	717	468	210	411	1,399	1,551	5,691
1994	457	269	136	100	724	482	218	423	1,466	1,606	5,880
1995	466	277	143	103	731	497	224	436	1,536	1,662	6,074
1996	470	285	150	105	735	504	231	446	1,594	1,720	6,242
1997	475	294	156	107	738	512	238	458	1,655	1,772	6,405
1998	480	303	163	109	742	519	243	469	1,718	1,825	6,571
1999	482	312	169	111	742	524	248	478	1,784	1,880	6,730
2000	482	321	174	113	742	524	250	488	1,843	1,927	6,864
					ANNUAL GROWTH RATES						
1981-1990	1.98	.34	6.12	1.83	1.66	1.81	.66	1.05	1.29	.84	1.32
1990-2000	1.25	2.90	3.99	2.46	.75	1.95	2.80	2.65	4.19	3.30	2.87
1981-2000	1.60	1.68	4.99	2.16	1.18	1.88	1.78	1.89	2.81	2.13	2.13

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,

JUNE 1984

Food and beverage production activity is related to population and its average annual growth of 1.9 percent is forecast to exceed that of population. The other manufacturing category includes a range of industries and is forecast to grow at an average annual rate of 1.3 percent between 1981 and 1990, and at 4.2 percent during the 1990's. This growth is attributable to the impact of high technology, a movement towards greater diversification of the industrial structure and developments related to liquefied natural gas (LNG).[4]

The construction industry is expected to experience low activity levels during the 1980's. This is due to the moderate levels of residential and non-residential construction investment in the first half of the eighties that result from low levels of migration and household formation, and increased utilization of existing capital without major re-investment (aside from major new projects). During the 1990's, the industry grows at an average rate of 3.3 percent as higher levels of investment in structures are made to accommodate an expanding economy and population.

---

[4] Economic activity related to LNG would be included in the major industry group of the petroleum and coal products industry.

Table 2.7

Forecast of Demographic Variables
(in thousands)

Year	Population	Households*	Housing Starts		
			Singles	Multiples	Total
1981	2744.0	996.6	19.2	22.4	41.6
1982	2791.8	1011.2	7.0	13.0	20.0
1983	2830.8	1028.9	14.0	8.6	22.6
1984	2872.8	1049.1	13.0	12.0	25.0
1985	2918.5	1071.2	15.0	12.0	27.0
1986	2965.8	1091.1	12.0	13.0	25.0
1987	3011.7	1108.8	10.0	13.0	23.0
1988	3057.4	1131.6	13.0	15.0	28.0
1989	3104.6	1157.5	14.0	17.0	31.0
1990	3152.5	1186.3	15.0	19.0	34.0
1991	3200.4	1214.9	15.0	19.0	34.0
1992	3248.9	1244.5	16.0	19.0	35.0
1993	3298.6	1273.8	16.0	19.0	35.0
1994	3349.5	1304.0	16.0	20.0	36.0
1995	3400.8	1334.0	16.0	20.0	36.0
1996	3452.7	1364.8	16.0	21.0	37.0
1997	3505.6	1395.5	16.0	21.0	37.0
1998	3560.3	1427.0	16.0	22.0	38.0
1999	3616.8	1459.4	17.0	22.0	39.0
2000	3675.9	1491.5	17.0	22.0	39.0

---

* Total households have been defined to include the Ministry's own estimates of households occupying mobile homes.

Table 2.7 summarizes the forecast of total population and the total number of households including those which occupy mobile homes. The number of households is forecast to increase at an average annual rate of 2.1 percent between 1981 and the year 2000 while the number of persons per household declines from 2.75 in 1981 to 2.46 by the year 2000. The forecast of housing construction required to accommodate the population is also presented.[5]

2.2 Energy Prices

The energy demand forecasting methodology employs forecasts of prices of refined petroleum products, natural gas and electricity at the sectoral level. This section will outline the forecasts of individual prices for these products, after a discussion of the underlying world oil and blended crude oil price forecasts.

2.2.1 World Crude Price

Table 2.8 presents a time profile of the official price of Saudi Arabian light crude in 1982 U.S. dollars per barrel. As is apparent from this table, there have been significant price variations in the historical period. The forecast presents a "smoothed" projection of the likely path of world oil prices without attempting to capture the correct year to year variations. It is unlikely that the timing of major dislocations in world supply/demand balances attributable to political instability could be anticipated correctly in any case.

---

[5] The stock of housing units, which is a major determinant in the demand for energy in the residential sector, has been calculated using the 1981 Census estimate of the housing stock, the housing starts from Table 2.7 and an estimated depreciation rate. Analysis of the 1961 and 1981 Census data and historic housing start data led to the adoption of depreciation rates of 0.533 percent for single detached dwellings and 0.744 percent for multiple dwellings.

It is assumed that world oil prices will remain constant in nominal terms (decline in real terms) through the end of 1984, as there is little upward pressure on oil prices. Demand remains sluggish due to the protracted economic recovery and consumer response to the major price increases of the late 1970's and there is sufficient surplus capacity and an eagerness to sell on the part of oil suppliers.

World oil prices are assumed to increase at the same rate as general inflation through 1986 and 1987 as the world economic recovery reaches maturity. The more buoyant world economic situation, the absence of alternate supplies caused by the delay in previously anticipated energy projects and the possibility of a supply dislocation are assumed to lead to real price increases of two percent in 1988 and 1989. Thereafter, it is assumed that world oil prices will increase at 1 percent per year in real terms as higher cost sources of supply are required to replace depleted reserves. Table 2.8 presents the forecast of the price of Saudi Arabian Light crude (FOB Saudi Arabia) in both Canadian and U.S. dollars. As the table suggests, the impact of the real price increases during the 1990's is effectively negated by the improvement in the Canada/U.S. exchange rate.

TABLE 2.8

WORLD OIL PRICE
(SAUDI ARABIAN MARKER CRUDE - FOB SAUDI ARABIA)

(DOLLARS/BARREL)

YEAR	IN U.S. DOLLARS		EXCHANGE RATE	IN CANADIAN DOLLARS	
	1982	CURRENT		1982	CURRENT
1974	16.28	9.05	1.02	18.63	8.87
1975	17.23	10.46	.97	20.44	10.78
1976	18.02	11.51	1.03	19.70	11.17
1977	18.79	12.70	.94	22.05	13.51
1978	17.49	12.70	.89	21.38	14.27
1979	22.81	18.00	.86	28.73	20.93
1980	34.79	30.00	.85	43.99	35.29
1981	35.71	33.71	.83	45.00	40.61
1982	31.67	31.67	.81	39.10	39.10
1983	26.40	27.51	.81	32.06	33.92
1984	25.44	27.70	.80	31.17	34.62
1985	24.75	28.30	.80	30.33	35.38
1986	24.46	29.50	.80	29.78	36.65
1987	24.45	30.97	.80	29.49	38.47
1988	24.87	32.92	.81	29.53	40.64
1989	25.38	35.27	.82	29.95	43.28
1990	25.78	37.26	.82	30.09	45.44
1991	26.06	39.17	.82	30.23	47.48
1992	26.34	41.17	.83	30.37	49.60
1993	26.62	43.28	.84	30.51	51.83
1994	26.90	45.49	.84	30.66	54.15
1995	27.22	47.64	.85	30.69	56.38
1996	27.52	49.84	.85	30.84	58.64
1997	27.81	52.13	.85	31.13	60.97
1998	28.11	54.54	.86	31.44	63.42
1999	28.41	57.05	.87	31.74	65.95
2000	28.75	59.46	.87	31.93	68.34

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

2.2.1.1 Blended Crude Oil Price

The blended crude oil price is calculated under the conditions established by the federal-provincial energy pricing agreements. It is assumed that the conventional old oil price (COOP) will be set at 75 percent of the world oil price landed in Montreal, on a quality adjusted basis, with the stipulation that well head prices do not decline. The special old oil price (SOOP) has been set at the new oil reference price (effective July 1983) and the share of total old oil production represented by SOOP oil has been assumed to rise by 1 percentage point per year from its 1983 share of 26 percent.

The Canadian crude oil supply/demand balance which underlies the calculation of the petroleum compensation charge (PCC) and the blended crude oil price has been drawn from the National Energy Program Update, prepared by the Federal Department of Energy, Mines and Resources.[6] A forecast of the blended crude oil at the Vancouver city gate is determined by adding gathering fees, the PCC, a Canadian Ownership Charge (COC) and transport charges between Edmonton and Vancouver to the price of old crude in Alberta. This blended crude price forecast is presented in Table 2.9.

2.2.1.2 Refined Petroleum Product Prices

Refined petroleum product (RPP) prices are determined by adding to the Vancouver refinery gate oil price (after accounting for the cost of crude consumed in the refinery) the refinery margin for each product, distribution margins and relevant taxes. The refinery margin was calculated on the assumption that refiners would set product margins in order to

---

[6] "National Energy Program Update 1982," Energy, Mines and Resources Canada, Ottawa, June 1982.

TABLE 2.9

BLENDED CRUDE OIL PRICE FORECAST

(DOLLARS/BARREL)

YEAR	OLD CRUDE	GATHERING FEES	P.C.C.	C.O.C.	SUB-TOTAL	TMP LEVY	VANC. PRICE	(1981 $)	REAL GROWTH
1981	18.88	.32	6.19	1.52	26.91	.59	27.50	27.50	----
1982	24.62	.33	6.30	1.15	32.40	.68	33.08	30.62	11.32
1983	29.75	.39	3.76	1.15	35.04	.82	35.87	31.03	1.36
1984	29.75	.56	3.76	1.15	35.22	.79	36.00	29.61	¯4.58
1985	29.75	.58	4.68	1.15	36.16	.80	36.97	28.95	¯2.22
1986	29.90	.62	5.63	1.15	37.30	.85	38.15	28.35	¯2.07
1987	30.71	.65	6.25	1.15	38.76	.90	39.66	27.84	¯1.81
1988	32.23	.69	7.05	1.15	41.12	.95	42.06	27.95	.41
1989	34.13	.72	8.08	1.15	44.08	1.00	45.08	28.50	1.94
1990	35.88	.76	9.13	1.15	46.92	1.04	47.96	28.98	1.69
1991	37.38	.79	9.83	1.15	49.15	1.08	50.24	29.15	.61
1992	38.95	.82	10.58	1.15	51.50	1.13	52.63	29.37	.73
1993	40.59	.85	11.37	1.15	53.96	1.17	55.14	29.58	.73
1994	42.31	.89	12.20	1.15	56.54	1.22	57.76	29.80	.73
1995	43.99	.92	13.03	1.15	59.09	1.27	60.36	29.94	.48
1996	45.64	.96	13.86	1.15	61.61	1.32	62.92	30.12	.61
1997	47.38	.99	14.73	1.15	64.24	1.36	65.60	30.45	1.09
1998	49.19	1.02	15.63	1.15	66.99	1.40	68.38	30.82	1.21
1999	51.08	1.05	16.57	1.15	69.84	1.44	71.28	31.19	1.20
2000	52.98	1.08	17.53	1.15	72.74	1.48	74.22	31.53	1.09

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

maintain a minimum revenue flow after the purchase of crude oil. The heavy fuel oil price has been set at a fixed ratio to the world crude price, reflecting the international nature of trade for this commodity. For the industrial market, this ratio has been maintained at 72 percent throughout the forecast period in accordance with recent historical experience. The refinery margins for all other products adjust (on a prorata basis) to maintain the minimum revenue requirement after the loss (gain) on sales of heavy fuel oil, net of taxes, have been realized.

The forecast of RPP prices is presented in Tables 2.10 and 2.11.

2.2.2 Natural Gas Prices

On September 15, 1983, the government announced broad policy measures to restructure the British Columbia natural gas industry. For the domestic market, the government has established a long-term wholesale pricing policy which links the price of natural gas to the refinery gate price of oil at Vancouver. The average wholesale price is to be phased in directly to a target level of 65% of the energy equivalent cost of crude at the Vancouver refinery gate by 1990. The federally administered natural gas and gas liquids tax (NGGLT) is assumed to decline to zero by 1984 while the Canadian ownership special charge (COSC) is assumed to remain constant at 14¢/gigajoule over the remainder of the forecast period.

TABLE 2.10

REFINED PETROLEUM PRODUCT PRICES

(DOLLARS PER GIGAJOULE)

YEAR	AVIATION TURBO	DIESEL FUEL OIL (NON-ROAD)	HEAVY FUEL OIL (INDUSTRIAL)	LIGHT FUEL OIL		LIQ. PET. GAS (INDUSTRIAL)	MOTOR GASOLINE (ROAD)
				(COMMERCIAL)	(RESIDENTIAL)		
1978	4.237	3.744	2.316	3.220	3.220	3.763	6.045
1979	4.683	4.328	2.729	3.743	3.743	4.113	6.580
1980	5.503	5.247	3.368	4.453	4.453	4.893	7.641
1981	8.397	7.942	5.409	6.670	6.293	7.329	10.352
1982	10.331	9.779	5.227	8.140	7.679	8.943	12.356
1983	11.497	10.883	4.615	9.060	8.507	9.955	13.563
1984	11.746	11.109	4.725	9.259	8.653	10.173	13.834
1985	12.101	11.438	4.836	9.501	8.880	10.439	14.214
1986	12.560	11.867	5.013	9.829	9.186	10.799	14.701
1987	13.129	12.399	5.264	10.239	9.569	11.249	15.304
1988	13.881	13.111	5.555	10.808	10.101	11.875	16.088
1989	14.781	13.970	5.906	11.511	10.758	12.647	17.021
1990	15.710	14.854	6.195	12.231	11.431	13.438	17.985
1991	16.471	15.577	6.468	12.814	11.975	14.078	18.775
1992	17.244	16.310	6.753	13.405	12.528	14.728	19.579
1993	18.054	17.079	7.051	14.025	13.107	15.409	20.421
1994	18.901	17.883	7.362	14.673	13.713	16.122	21.301
1995	19.761	18.699	7.660	15.329	14.326	16.842	22.195
1996	20.585	19.482	7.961	15.963	14.918	17.538	23.050
1997	21.408	20.266	8.272	16.604	15.518	18.243	23.900
1998	22.261	21.081	8.597	17.271	16.142	18.976	24.783
1999	23.148	21.926	8.935	17.965	16.789	19.738	25.699
2000	24.056	22.792	9.252	18.672	17.451	20.515	26.637
				ANNUAL GROWTH RATES			
1981-1990	7.21	7.20	1.52	6.97	6.86	6.97	6.33
1990-2000	4.35	4.37	4.09	4.32	4.32	4.32	4.01
1981-2000	5.70	5.71	2.87	5.57	5.51	5.57	5.10

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,

JUNE 1984

TABLE 2.11

REFINED PETROLEUM PRODUCT PRICES

(1982 DOLLARS PER GIGAJOULE)

YEAR	AVIATION TURBO	DIESEL FUEL OIL (NON-ROAD)	HEAVY FUEL OIL (INDUSTRIAL)	LIGHT FUEL OIL (COMMERCIAL)	LIGHT FUEL OIL (RESIDENTIAL)	LIQ, PET, GAS (INDUSTRIAL)	MOTOR GASOLINE (ROAD)
1978	6.305	5.572	3.447	4.792	4.792	5.600	8.996
1979	6.469	5.979	3.770	5.171	5.171	5.682	9.090
1980	6.951	6.628	4.254	5.625	5.625	6.181	9.652
1981	9.279	8.776	5.977	7.371	6.954	8.099	11.440
1982	10.331	9.779	5.227	8.140	7.679	8.943	12.356
1983	10.898	10.316	4.375	8.588	8.064	9.437	12.857
1984	10.656	10.078	4.287	8.400	7.850	9.229	12.550
1985	10.505	9.930	4.198	8.248	7.709	9.062	12.340
1986	10.385	9.812	4.145	8.127	7.595	8.929	12.155
1987	10.288	9.716	4.125	8.023	7.498	8.815	11.992
1988	10.361	9.786	4.146	8.067	7.539	8.863	12.008
1989	10.555	9.976	4.217	8.220	7.682	9.031	12.155
1990	10.736	10.151	4.234	8.359	7.812	9.184	12.291
1991	10.822	10.235	4.250	8.419	7.868	9.250	12.336
1992	10.896	10.306	4.267	8.470	7.916	9.306	12.372
1993	10.970	10.377	4.284	8.522	7.964	9.362	12.408
1994	11.042	10.447	4.301	8.572	8.011	9.418	12.444
1995	11.100	10.503	4.303	8.610	8.047	9.460	12.467
1996	11.173	10.574	4.321	8.664	8.097	9.519	12.511
1997	11.281	10.679	4.359	8.749	8.177	9.613	12.594
1998	11.387	10.784	4.398	8.835	8.257	9.707	12.677
1999	11.498	10.891	4.438	8.923	8.339	9.804	12.765
2000	11.600	10.990	4.461	9.003	8.415	9.892	12.844
				ANNUAL GROWTH RATES			
1981-1990	1.63	1.63	¯3.76	1.41	1.30	1.41	.80
1990-2000	.78	.80	.52	.75	.75	.75	.44
1981-2000	1.18	1.19	¯1.53	1.06	1.01	1.06	.61

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

The wholesale prices for each of the three domestic utilities are calculated by applying appropriate differentials to the provincial average wholesale price and the resulting utility wholesale prices are used as the base for determining the gas prices for the various consumer classes. The sector natural gas prices are determined by using the consumption patterns of the sector to establish an applicable weighted average gas price. Where appropriate, the average price is calculated for different utilities and aggregated to a single price series. The resulting forecasts of average provincial wholesale prices and natural gas prices for selected sectors are presented in Tables 2.12 and 2.13 in current and constant (1982) dollars.

2.2.3 Electricity Prices

The forecast of electricity price increases takes cognizance of Special Direction Number One (Revised March 14, 1984) which requires B.C. Hydro to achieve an interest coverage ratio of 1.3:1 by fiscal year 1990/91. The Special Direction originally required B.C. Hydro to reach the interest coverage ratio by fiscal 1983/84. However in light of the debt loads associated with the Revelstoke Dam and the Cheekye-Dunsmuir power line to Vancouver Island, and other factors, it became clear that the target interest coverage ratio could not be achieved in fiscal 1983/84 without substantial rate increases. Consequently, the date for achieving this ratio was moved to 1990/91.

Additionally, the scheduled 1984 increase in water rental fees was replaced by an indexed charge. Analysis by the Ministry indicates that the combined effects of these changes will result in electricity real price increases in the order of 2 percent per year between 1983 and 1991.

TABLE 2.12

AVERAGE NATURAL GAS PRICES

(DOLLARS PER GIGAJOULE)

YEAR	AVERAGE WHOLESALE	RESIDENTIAL	COMMERCIAL	INDUSTRIAL			
				PAPER	WOOD	REFINERIES	OTHER MAN.
1978		2.248	1.941	1.328	1.706	1.366	1.705
1979		2.320	2.074	1.468	1.936	1.439	1.935
1980		2.420	2.161	1.541	2.054	1.509	2.054
1981	1.407	3.180	2.975	2.204	2.739	2.279	2.739
1982	1.832	4.150	4.002	2.953	3.499	3.178	3.499
1983	2.082	4.260	4.120	2.975	3.542	3.231	3.542
1984	2.631	4.450	4.323	3.146	3.724	3.445	3.724
1985	2.928	4.790	4.665	3.456	4.055	3.734	4.055
1986	3.265	5.200	5.072	3.852	4.473	4.087	4.473
1987	3.642	5.650	5.532	4.291	4.954	4.473	4.943
1988	4.122	6.210	6.099	4.836	5.532	4.954	5.532
1989	4.704	6.850	6.762	5.489	6.206	5.532	6.206
1990	5.315	7.530	7.469	6.120	6.869	6.174	6.869
1991	5.682	7.990	7.929	6.506	7.297	6.581	7.297
1992	5.957	8.350	8.293	6.816	7.629	6.891	7.629
1993	6.246	8.720	8.667	7.137	7.982	7.201	7.982
1994	6.554	9.120	9.063	7.469	8.357	7.544	8.357
1995	6.855	9.520	9.459	7.800	8.721	7.875	8.721
1996	7.155	9.910	9.855	8.121	9.074	8.218	9.074
1997	7.468	10.290	10.251	8.464	9.437	8.549	9.437
1998	7.788	10.700	10.657	8.806	9.812	8.902	9.812
1999	8.122	11.120	11.075	9.170	10.208	9.277	10.208
2000	8.466	11.540	11.503	9.534	10.604	9.641	10.604
ANNUAL GROWTH RATES							
1981-1990	15.91	10.05	10.77	12.02	10.76	11.71	10.76
1990-2000	4.77	4.36	4.41	4.53	4.44	4.56	4.44
1981-2000	9.90	7.02	7.38	8.01	7.38	7.89	7.38

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

TABLE 2.13

AVERAGE NATURAL GAS PRICES

(1982 DOLLARS PER GIGAJOULE)

YEAR	AVERAGE WHOLESALE	RESIDENTIAL	COMMERCIAL	INDUSTRIAL PAPER	INDUSTRIAL WOOD	INDUSTRIAL REFINERIES	INDUSTRIAL OTHER MAN.
1978		3.345	2.888	1.976	2.538	2.033	2.537
1979		3.205	2.865	2.028	2.674	1.988	2.673
1980		3.057	2.730	1.946	2.595	1.906	2.595
1981	1.555	3.514	3.287	2.436	3.027	2.519	3.027
1982	1.832	4.150	4.002	2.953	3.499	3.178	3.499
1983	1.973	4.038	3.905	2.820	3.357	3.063	3.357
1984	2.387	4.037	3.922	2.854	3.378	3.126	3.378
1985	2.542	4.158	4.050	3.000	3.521	3.242	3.521
1986	2.700	4.299	4.193	3.185	3.698	3.379	3.698
1987	2.854	4.427	4.335	3.362	3.882	3.505	3.874
1988	3.077	4.635	4.552	3.610	4.129	3.698	4.129
1989	3.359	4.892	4.929	3.920	4.432	3.950	4.432
1990	3.632	5.146	5.104	4.183	4.695	4.219	4.695
1991	3.734	5.250	5.209	4.274	4.795	4.324	4.795
1992	3.764	5.276	5.240	4.307	4.821	4.354	4.821
1993	3.795	5.298	5.266	4.336	4.850	4.375	4.850
1994	3.829	5.328	5.295	4.363	4.882	4.407	4.882
1995	3.850	5.347	5.313	4.381	4.898	4.424	4.898
1996	3.883	5.379	5.349	4.408	4.925	4.460	4.925
1997	3.935	5.422	5.402	4.460	4.973	4.505	4.973
1998	3.984	5.473	5.451	4.505	5.019	4.554	5.019
1999	4.034	5.523	5.501	4.555	5.070	4.608	5.070
2000	4.082	5.564	5.546	4.597	5.113	4.649	5.113
ANNUAL GROWTH RATES							
1981-1990	9.88	4.33	5.01	6.19	5.00	5.90	5.00
1990-2000	1.17	.78	.83	.95	.86	.97	.86
1981-2000	5.21	2.45	2.79	3.40	2.80	3.28	2.80

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

Beyond 1991, average residential prices have been phased in to \$16.67/GJ (\$1982) or about 60 mills/KWH (\$1982) by the year 2000. This assumption is in agreement with the broad objective of pricing energy commodities to reflect long run replacement costs as put forth in the February 1980 Energy Policy Statement.[7] Electricity prices in all categories have been escalated at the same rates and are reported in Tables 2.14 and 2.15 in current and constant (1982) dollars.

---

[7] "An Energy Secure British Columbia: The Challenge and the Opportunity," Ministry of Energy Mines and Petroleum Resources, February 1980. Also see, the Ministry publication "Natural Gas Supply to Vancouver Island: Technical Report" Victoria, April 1983, Appendix D contained an estimate of the cost of energy generated from Site "C" to the residential consumer of 55 mills/Kwh (\$ 1982).

TABLE 2.14

AVERAGE ELECTRICITY PRICES

(DOLLARS PER GIGAJOULE)

YEAR	RESIDENTIAL	COMMERCIAL	INDUSTRIAL			
			PAPER	WOOD	REFINERIES	OTHER MAN.
1978	10.084	8.512	3.609	6.833	3.393	6.562
1979	10.280	8.732	3.957	7.153	3.738	6.924
1980	10.695	9.450	4.702	8.122	4.463	8.124
1981	11.031	9.960	5.584	8.752	5.399	8.635
1982	12.776	11.762	6.437	10.385	6.172	10.335
1983	13.709	12.590	6.800	11.116	6.506	11.052
1984	14.612	13.420	7.248	11.849	6.935	11.780
1985	15.575	14.304	7.726	12.629	7.392	12.557
1986	16.681	15.320	8.274	13.526	7.917	13.448
1987	17.951	16.485	8.904	14.555	8.519	14.471
1988	19.225	17.656	9.536	15.589	9.124	15.499
1989	20.492	18.819	10.164	16.616	9.725	16.520
1990	21.842	20.059	10.834	17.711	10.366	17.609
1991	23.170	21.279	11.493	18.788	10.996	18.680
1992	24.579	22.573	12.192	19.930	11.665	19.815
1993	26.073	23.945	12.933	21.142	12.374	21.020
1994	27.314	25.084	13.548	22.148	12.963	22.020
1995	28.613	26.278	14.193	23.201	13.579	23.068
1996	29.831	27.396	14.797	24.188	14.157	24.047
1997	30.949	28.423	15.352	25.095	14.688	24.951
1998	32.110	29.489	15.927	26.037	15.239	25.887
1999	33.314	30.595	16.525	27.013	15.810	26.858
2000	34.564	31.742	17.145	28.026	16.403	27.865
			ANNUAL GROWTH RATES			
1981-1990	7.89	8.09	7.64	8.15	7.52	8.24
1990-2000	4.70	4.70	4.70	4.70	4.70	4.70
1981-2000	6.20	6.29	6.08	6.32	6.02	6.36

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

TABLE 2.15

AVERAGE ELECTRICITY PRICES

(1982 DOLLARS PER GIGAJOULE)

YEAR	RESIDENTIAL	COMMERCIAL	INDUSTRIAL			
			PAPER	WOOD	REFINERIES	OTHER MAN.
1978	15.007	12.667	5.371	10.169	5.049	9.765
1979	14.202	12.063	5.466	9.882	5.164	9.565
1980	13.509	11.937	5.939	10.259	5.637	10.262
1981	12.190	11.006	6.171	9.672	5.966	9.542
1982	12.776	11.762	6.437	10.385	6.172	10.335
1983	12.995	11.935	6.446	10.537	6.167	10.477
1984	13.256	12.175	6.576	10.750	6.292	10.687
1985	13.521	12.418	6.707	10.964	6.417	10.901
1986	13.792	12.667	6.841	11.183	6.546	11.119
1987	14.067	12.918	6.977	11.406	6.676	11.340
1988	14.349	13.178	7.118	11.636	6.810	11.568
1989	14.633	13.439	7.258	11.865	6.945	11.797
1990	14.927	13.708	7.404	12.104	7.084	12.034
1991	15.224	13.981	7.551	12.345	7.225	12.274
1992	15.531	14.263	7.704	12.593	7.371	12.521
1993	15.842	14.549	7.858	12.846	7.518	12.772
1994	15.957	14.654	7.915	12.939	7.573	12.864
1995	16.072	14.760	7.972	13.032	7.627	12.957
1996	16.191	14.870	8.031	13.128	7.684	13.053
1997	16.308	14.977	8.090	13.224	7.740	13.148
1998	16.425	15.084	8.147	13.319	7.795	13.242
1999	16.547	15.197	8.208	13.418	7.853	13.341
2000	16.666	15.306	8.267	13.514	7.909	13.436
ANNUAL GROWTH RATES						
1981-1990	2.28	2.47	2.05	2.52	1.93	2.61
1990-2000	1.11	1.11	1.11	1.11	1.11	1.11
1981-2000	1.66	1.75	1.55	1.78	1.49	1.82

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,

JUNE 1984

CHAPTER 3

RESIDENTIAL SECTOR

3.0 Introduction

The residential sector is defined to include single detached and single attached units, apartments and mobile dwelling structures. Energy consumed in these dwelling types for space heating, water heating and operation of household appliances, and lighting represents the largest portion of residential energy use. However, energy used for heating private swimming pools and diesel fuel oil used for farming operations is also included here in the residential demand. This sector is serviced principally by natural gas, electricity and light fuel oil. The following discussion, however, employs the term "oil" to encompass various refined petroleum products including light fuel oil, heavy fuel oil, LPG, kerosene and stove oil.

3.1 Historical Profile

Table 3.1 presents a historical profile of energy consumption in the residential sector from 1961 to 1981. Over these 21 years, residential energy use in British Columbia has grown at an average annual rate of about 3.4 percent per year. Energy use per household,[1] also increased dramatically in the 1960's from 124 GJ in 1961 to 153 GJ in 1971. Over the 1971-1981 period, however, consumption per household experienced a significant decline and dropped to 124 GJ by 1980,[2] the same level as in 1961.

---

[1] Excluding diesel fuel oil.

[2] 1981 experienced a "warm winter" and energy requirements were significantly lower than would otherwise have occurred.

TABLE 3.1

HISTORICAL RESIDENTIAL SECTOR ENERGY REQUIREMENTS

(PETAJOULES)

YEAR	NATURAL GAS	COAL AND COKE	HEAVY FUEL OIL	LIGHT FUEL OIL	L.P.G.	DIESEL FUEL OIL	ELECT.	TOTAL REQTS
1961	10.648	6.452	2.290	28.589	1.259	2.362	7.811	59.411
1962	13.060	5.878	2.235	30.122	2.391	2.256	8.448	64.390
1963	15.549	4.771	3.233	30.366	2.900	.295	8.776	65.891
1964	18.329	4.090	1.710	31.586	3.161	1.219	9.673	69.769
1965	20.125	2.920	1.988	29.416	3.613	1.441	10.398	69.901
1966	23.845	2.073	1.884	27.751	4.878	2.193	11.608	74.231
1967	24.807	1.484	1.353	27.055	3.782	2.253	12.647	73.380
1968	28.055	1.019	1.363	27.075	4.195	2.601	14.155	78.461
1969	31.645	.841	1.902	31.719	5.980	1.988	15.072	89.147
1970	32.959	.678	2.039	31.487	6.041	2.100	16.725	92.029
1971	35.966	.562	2.675	36.706	7.585	2.256	18.309	104.059
1972	41.408	.441	2.088	40.873	6.454	1.997	19.541	112.803
1973	43.121	.347	1.916	35.206	6.382	2.431	21.208	110.611
1974	43.213	.273	1.549	30.861	6.583	2.722	22.301	107.502
1975	48.555	.002	1.801	34.074	6.482	2.583	25.319	118.815
1976	50.819	.016	.593	31.031	5.419	3.417	26.996	118.290
1977	53.499	.254	.512	30.626	5.655	3.655	32.112	126.313
1978	51.887	.044	.229	29.434	.000	3.856	29.691	115.144
1979	54.051	.018	.376	28.070	2.856	3.670	31.125	120.165
1980	56.257	.003	.472	26.186	2.957	2.916	33.243	122.033
1981	55.396	.951	.376	20.181	2.930	2.951	33.785	116.569

ANNUAL GROWTH RATES

1961-1971	12.94	¯21.66	1.57	2.53	19.67	¯.46	8.89	5.76
1971-1981	4.41	5.40	¯17.83	¯5.81	¯9.07	2.72	6.32	1.14

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

In 1981, the residential sector accounted for about 17 percent of the total energy use in British Columbia. Approximately 61 percent of residential energy is used for space heating applications, 18 percent is used for water heating and the remaining 21 percent is for appliance and other uses.

Historically, both natural gas and electricity have expanded their market shares quite dramatically and primarily at the expense of oil. In 1962, natural gas and electricity accounted for 18 and 13 percent respectively of the residential energy demand. By 1981, these shares had risen to about 48 and 29 percent. The share of oil on the other hand, declined from 55 percent in 1962 to 23 percent in 1981.

Currently, about 76 percent of residential natural gas is used for space heating and 21 percent for water heating. By comparison, over 92 percent of residential oil use is for space heating applications. Electricity, on the other hand, is used principally for the operation of household appliances with only approximately 19 percent of residential electricity used for domestic water heating and about 16 percent for space heating.

3.2 Forecast Period Assumptions

Residential sector energy requirements were forecast separately for the mainland and Vancouver Island. These requirements were forecast by relating energy demand with growth in housing activity, real personal disposable income and energy prices. The individual fuel demands were, however, derived by incorporating forecasts of relative fuel prices to capture the cross elasticity impact on market shares for each fuel, and the ratio of multiple dwelling units to total dwelling units.[3]

In the case of Vancouver Island, the market shares were initially determined for electricity and oil using the model. The share of natural gas was then estimated by incorporating the displacement levels in electricity and oil market shares resulting from the introduction of natural gas service to the Island starting in 1986. The displacement levels employed here were derived from the fuel demand forecasts reported in a staff study of natural gas supply to Vancouver Island.[4]

The major assumptions underlying the energy forecast are discussed below.

3.2.1 Economic and Demographic Activity

The major economic and demographic assumptions which underly this forecast are presented in Chapter 2. Those assumptions which are of particular relevance to the residential sector are briefly reviewed below.

The British Columbia population is forecast to increase from 2.744 million in 1981 to 3.676 million in 2000 at an annual average growth rate of 1.6 percent. The net migration to British Columbia is expected to decrease from 36.4 thousand in 1981 to less than 22 thousand per year in the balance of the 1980's. In the 1990's, however, the population gain from net migration is expected to increase from 26.5 thousand in 1990 to 48.5 thousand in 2000 reflecting the impact of a protracted economic recovery following the period of low economic performance in the 1980's.

---

[3] A full description of the model specifications is presented in March 1983 Staff Paper "The B.C. Energy Demand Forecasting and Planning Model."

[4] "Natural Gas Supply to Vancouver Island Technical Report" Ministry of Energy, Mines and Petroleum Resources, April 1983.

The number of households in B.C. is forecast to grow at an annual average rate of 2.1 percent from 996.6 thousand in 1981 to 1491.6 thousand by 2000.

The proportion of households established in multiple dwellings (apartments, row, duplexes) is forecast to increase from 32.2 percent in 1981 to 39.4 percent in 2000, reflecting the impacts of the higher growth rate in the 65+ population segment which tends to prefer multiple units, the increased cost of land and the decrease in the average number of persons per household. This shift is important to the forecast of energy requirements in determining both the fuel selection and intensity of fuel consumption.

Real personal disposable income per household is forecast to increase at an annual average rate of 0.8 percent between 1981 and the year 2000.

3.2.2 Energy Prices

The forecast of real energy prices used for the residential sector is presented in Tables 2.11 through 2.15. Between 1981 and the year 2000, the real price of residential natural gas is forecast to increase at an average annual rate of 2.5 percent while the real prices of electricity and light fuel oil are forecast to increase at 1.8 and 1.0 percent respectively. While the growth rate of natural gas prices is higher than that of light fuel oil and electricity, it is expected that natural gas will remain the preferred fuel as its price in 1990 reaches only about 66 percent of the price of light fuel oil and about 52 percent of the price of electricity (based on natural gas converted to output joules at a 66 percent efficiency).

Between 1978 and 1981, the real price of light fuel oil increased at a significantly faster annual growth rate (13.2 percent) than either natural gas (1.7 percent) or electricity (-6.7 percent), and despite the relatively lower growth in oil prices over the forecast period there is a significant decrease in oil's market share in response to these recent large relative price increases.

3.2.3 Other Assumptions

The fuel prices employed in the market share analysis are expressed as output joule prices, where the fuel price is divided by the efficiency with which each fuel may be converted to "useful energy". Over the historical period, these conversion efficiencies have been assumed to remain constant. With the introduction of high efficiency natural gas furnaces which have name plate efficiencies of 90 to 95 percent, it is forecast that the average conversion efficiency of natural gas furnaces will rise over time. The actual operating efficiency of these new furnaces is expected to be somewhat lower than name plate due to normal losses resulting from furnace cycling.

Installing a high efficiency natural gas furnace requires a major capital commitment and it appears unlikely that there will be a complete replacement of conventional with high efficiency furnaces.[5] It is assumed that high efficiency furnaces will make modest inroads into the stock of furnaces over time as the existing stock is turned over.

Average fuel efficiencies were assumed to be initially the same for both oil and natural gas furnaces. (see Table 3.2). It has been further assumed that over time there will be a gradual decline in the number of oil customers due to conversions and that relatively fewer dwellings will install a new oil furnace since natural gas will remain the preferred fuel where available. Consequently, the average fuel efficiency for natural gas increases while that for oil is held constant.

Table 3.2
Heating Fuel Efficiency Assumptions

	Natural Gas		LFO	HFO	LPG
	Mainland	Vancouver Island			
1981-1985	0.65	--	0.65	0.80	0.65
1986-1990	0.66	0.67	0.65	0.80	0.65
1991-1995	0.68	0.70	0.65	0.80	0.65
1996-2000	0.70	0.72	0.65	0.80	0.65

---

[5] In the Natural Gas Supply to Vancouver Island Technical Report, it was reported that the private cost of a gas furnace with an efficiency rating 20 percentage points higher than the conventional furnace would be approximately 675 dollars (1982) greater than that associated with a conventional furnace. Assuming fuel efficiencies of 70 and 90 percent for new conventional and high efficiency furnaces, the period of time for an individual to recover his incremental investment would range from about 6.2 to 7.9 years over the forecast period, given our price forecast and an average annual consumption of 70 (output) gigajoules. As the actual operating efficiency may be somewhat less than 90 percent and real price increases for heating equipment may occur, the realized payback periods may be somewhat longer.

A modest allowance was made for the introduction of heat pumps. It is expected that by the year 2000, some 4.0 percent of electric space heat installations will employ the heat pump.

The impact of the Canada Oil Substitution Program (COSP) has been incorporated within the forecast through an effective reduction in the cost of space heat delivered by natural gas relative to other fuels. The after tax nominal value of the COSP grant has been annualized using a long term interest rate and expressed on a gigajoule basis assuming an average consumption of 70 (output) gigajoules. The program is assumed to be effective through 1990 and has a marginal impact on the market share captured by natural gas.

An explicit allowance for the role of renewables[6] in meeting residential energy requirements has been made in this forecast. The consumption of renewable energy has occured throughout the historical period although there is insufficient data with which to prepare time series estimates. Over the historical period it is assumed that the substitution of renewable for other energy sources has been incorporated in the energy price coefficient. With the outlook for generally increasing real energy prices, a public perception of increasingly expensive energy and the increasing attractiveness of the new technology, it has been assumed that the renewable energy sources will capture a larger share of the energy consumption than historically realized. By the year 2000, the incremental consumption of renewables is forecast to reduce consumption of purchased output energy by 3.0 percent on the Mainland and 4.0 percent on Vancouver Island.

---

[6] The term renewable is taken here to include wood, solar and wind energy, but to exclude hydroelectricity.

3.3 Total Energy and Fuels Requirements Forecast

Total provincial energy requirements have been obtained by adding together the requirements for Vancouver Island and the mainland. For both of these regions, the forecasts were prepared using the B.C. Energy Forecasting and Planning Model in which the total energy requirements are determined by linking energy use per household to the average price of energy and other variables. The estimated market shares obtained from price elasticity relationships between fuels were then applied to the forecast of total energy to produce the forecast of requirements for each fuel.[7]

Provincial energy requirements for the residential sector as reported in Table 3.3 are forecast to increase from 117.0 petajoules in 1981 to 162.6 petajoules in the year 2000 at an average annual rate of 1.7 percent. Between 1981 and 1990 total energy requirements are expected to grow at an average annual rate of 1.8 percent, declining subsequently to an average of 1.7 percent in the 1990's.

---

[7] The forecast of derived energy requirements was tempered in a number of areas to capture relevant behaviour adequately. As an example, the lag in the price response factor was extended and the price coefficients for the Mainland equations were modified.

TABLE 3.3

PROVINCIAL RESIDENTIAL SECTOR
ENERGY REQUIREMENTS

(PETAJOULES)

YEAR	NATURAL GAS	COAL AND COKE	HEAVY FUEL OIL	LIGHT FUEL OIL	L,P,G,	ELECT,	DIESEL FUEL OIL	RENEWABLE ENERGY	TOTAL REQTS
1978	51.062	.045	.228	29.228	3.167	29.703	3.851	.000	117.284
1979	54.092	.018	.375	28.019	2.856	31.145	3.665	.000	120.170
1980	56.349	.003	.462	25.706	2.915	33.367	2.912	.000	121.714
1981	56.030	.950	.376	20.167	2.927	33.660	2.951	.000	117.061
1982	61.276	.000	.421	20.168	2.936	35.969	2.887	.000	123.657
1983	64.886	.000	.373	18.392	2.625	38.693	2.888	.000	127.857
1984	65.587	.000	.326	16.340	2.303	41.122	2.950	.000	128.628
1985	66.747	.000	.295	15.030	2.096	43.246	3.015	.000	130.429
1986	67.966	.000	.259	12.417	1.807	44.237	3.115	.212	130.013
1987	68.493	.000	.256	11.846	1.771	44.915	3.184	.413	130.878
1988	69.475	.000	.277	12.165	1.889	45.390	3.291	.638	133.125
1989	70.541	.000	.298	12.472	2.007	45.994	3.400	.871	135.583
1990	71.366	.000	.319	12.718	2.120	46.650	3.514	1.096	137.783
1991	69.790	.000	.332	13.226	2.206	47.314	3.630	1.344	137.842
1992	70.092	.000	.356	14.109	2.363	48.135	3.751	1.603	140.409
1993	70.763	.000	.375	14.826	2.489	48.948	3.877	1.856	143.134
1994	71.879	.000	.386	15.229	2.557	49.826	4.006	2.137	146.020
1995	73.139	.000	.394	15.544	2.609	50.750	4.139	2.429	149.004
1996	73.047	.000	.385	15.284	2.554	51.749	4.253	2.719	149.991
1997	74.421	.000	.389	15.465	2.583	52.939	4.371	3.039	153.207
1998	75.757	.000	.391	15.559	2.598	54.176	4.493	3.369	156.343
1999	77.130	.000	.393	15.634	2.609	55.455	4.617	3.693	159.531
2000	78.445	.000	.393	15.656	2.613	56.688	4.719	4.044	162.558

ANNUAL GROWTH RATES

1981-1990	2.72	.00	¯1.81	¯4.99	¯3.52	3.69	1.96	.00	1.83
1990-2000	.95	.00	2.11	2.10	2.11	1.97	2.99	13.95	1.67
1981-2000	1.79	.00	.23	¯1.32	¯.60	2.78	2.50	.00	1.74

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

TABLE 3.4

PROVINCIAL RESIDENTIAL SECTOR
MARKET SHARES

(INPUT JOULES ; PERCENT)

YEAR	NATURAL GAS	COAL AND COKE	HEAVY FUEL OIL	LIGHT FUEL OIL	L.P.G.	ELECT.	DIESEL FUEL OIL	RENEWABLE ENERGY	TOTAL REDTS
1978	43.54	.04	.19	24.92	2.70	25.33	3.28	.00	100.00
1979	45.01	.01	.31	23.32	2.38	25.92	3.05	.00	100.00
1980	46.30	.00	.38	21.12	2.39	27.41	2.39	.00	100.00
1981	47.86	.81	.32	17.23	2.50	28.75	2.52	.00	100.00
1982	49.55	.00	.34	16.31	2.37	29.09	2.33	.00	100.00
1983	50.75	.00	.29	14.38	2.05	30.26	2.26	.00	100.00
1984	50.99	.00	.25	12.70	1.79	31.97	2.29	.00	100.00
1985	51.17	.00	.23	11.52	1.61	33.16	2.31	.00	100.00
1986	52.28	.00	.20	9.55	1.39	34.03	2.40	.00	100.00
1987	52.33	.00	.20	9.05	1.35	34.32	2.43	.16	100.00
1988	52.19	.00	.21	9.14	1.42	34.10	2.47	.32	100.00
1989	52.03	.00	.22	9.20	1.48	33.92	2.51	.48	100.00
1990	51.80	.00	.23	9.23	1.54	33.86	2.55	.64	100.00
1991	50.63	.00	.24	9.60	1.60	34.32	2.63	.80	100.00
1992	49.92	.00	.25	10.05	1.68	34.28	2.67	.97	100.00
1993	49.44	.00	.26	10.36	1.74	34.20	2.71	1.14	100.00
1994	49.23	.00	.26	10.43	1.75	34.12	2.74	1.30	100.00
1995	49.09	.00	.26	10.43	1.75	34.06	2.78	1.46	100.00
1996	48.70	.00	.26	10.19	1.70	34.50	2.84	1.63	100.00
1997	48.58	.00	.25	10.09	1.69	34.55	2.85	1.81	100.00
1998	48.46	.00	.25	9.95	1.66	34.65	2.87	1.98	100.00
1999	48.35	.00	.25	9.80	1.64	34.76	2.89	2.15	100.00
2000	48.26	.00	.24	9.63	1.61	34.87	2.90	2.31	100.00

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

The share of total energy requirements captured by natural gas as reported in Table 3.4 increases only marginally from 47.9 percent in 1981 to 52 percent by 1986 and then decreases to 48.3 percent in the year 2000 as requirements reach 78.4 PJ. Electricity's share increases from 28.8 percent in 1981 to 34.0 percent by 1986 and increases marginally to 34.9 percent by the year 2000 while requirements reach 56.7 PJ. Oil's share declines into the mid 1980's in response to major price increases of the late 1970's and early 1980's and incentives available under the off-oil programs. In the period following the mid 1980's, oil's share rises moderately as it experiences lower price increases than competing fuels and then declines due to the growth of multiple dwelling units and the impact of renewable energy use.

As shown in Table 3.3, diesel fuel oil requirements are projected to increase at an average annual rate of 2.5 percent from almost 3.0 PJ in 1981 to 4.7 PJ in the year 2000. Renewable energy requirements have been assumed to reach 2.5 percent of total energy requirements by the year 2000 or 4.0 PJ.

3.3.1 Mainland

Energy requirements[8] on the Mainland as indicated in Table 3.5 are forecast to increase from 96.9 petajoules in 1981 to 115.2 petajoules in 1990 and to 134.2 petajoules in the year 2000. This represents an average annual growth rate of 1.9 percent between 1981 and 1990, 1.5 percent during the 1990's, with an overall average growth rate of 1.7 percent.

---

[8] Energy requirements reported for the Mainland and Vancouver Island do not include diesel fuel oil demand as it was not possible to regionalize this fuel demand due to insufficient historical data.

TABLE 3.5

MAINLAND RESIDENTIAL SECTOR
ENERGY REQUIREMENTS

(PETAJOULES)

YEAR	NATURAL GAS	COAL AND COKE	HEAVY FUEL OIL	LIGHT FUEL OIL	L.P.G.	ELECT.	RENEWABLE ENERGY	TOTAL REQTS
1978	51.062	.037	.154	20.143	2.538	23.105	.000	97.119
1979	54.092	.015	.246	18.738	2.191	24.354	.000	99.636
1980	56.349	.002	.296	16.833	2.234	26.196	.000	101.910
1981	56.030	.731	.237	11.715	2.207	25.964	.000	96.884
1982	61.276	.000	.349	11.740	2.229	28.200	.000	103.794
1983	64.886	.000	.304	10.212	1.939	30.550	.000	107.891
1984	65.587	.000	.261	8.792	1.669	32.406	.000	108.715
1985	66.747	.000	.234	7.875	1.495	34.031	.000	110.382
1986	65.784	.000	.215	7.220	1.371	34.963	.169	109.722
1987	65.222	.000	.218	7.329	1.392	35.719	.340	110.220
1988	65.055	.000	.244	8.192	1.555	36.280	.518	111.844
1989	64.918	.000	.270	9.067	1.721	36.948	.702	113.626
1990	64.490	.000	.295	9.936	1.886	37.654	.890	115.151
1991	62.837	.000	.308	10.351	1.965	38.311	1.085	114.857
1992	62.756	.000	.331	11.131	2.113	39.132	1.288	116.751
1993	63.043	.000	.349	11.747	2.230	39.963	1.500	118.832
1994	63.762	.000	.359	12.071	2.292	40.848	1.721	121.053
1995	64.619	.000	.366	12.319	2.339	41.777	1.951	123.371
1996	64.500	.000	.357	12.006	2.279	42.679	2.194	124.015
1997	65.612	.000	.361	12.133	2.304	43.764	2.446	126.620
1998	66.686	.000	.363	12.196	2.315	44.890	2.707	129.157
1999	67.791	.000	.364	12.248	2.325	46.049	2.979	131.756
2000	68.840	.000	.364	12.261	2.328	47.170	3.257	134.220
ANNUAL GROWTH RATES								
1981-1990	1.57	.00	2.46	¯1.81	¯1.73	4.22	.00	1.94
1990-2000	.65	.00	2.12	2.12	2.13	2.28	13.85	1.54
1981-2000	1.09	.00	2.28	.24	.28	3.19	.00	1.73

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

TABLE 3.6

MAINLAND RESIDENTIAL SECTOR
MARKET SHARES

(INPUT JOULES ; PERCENT)

YEAR	NATURAL GAS	COAL AND COKE	HEAVY FUEL OIL	LIGHT FUEL OIL	L.P.G.	ELECT.	RENEWABLE ENERGY	TOTAL REQTS
1978	52.58	.04	.16	20.74	2.61	23.87	.00	100.00
1979	54.29	.02	.25	18.81	2.20	24.44	.00	100.00
1980	55.29	.00	.29	16.52	2.19	25.71	.00	100.00
1981	57.83	.75	.24	12.09	2.28	26.80	.00	100.00
1982	59.04	.00	.34	11.31	2.15	27.17	.00	100.00
1983	60.14	.00	.28	9.47	1.80	28.32	.00	100.00
1984	60.33	.00	.24	8.09	1.54	29.81	.00	100.00
1985	60.47	.00	.21	7.13	1.35	30.83	.00	100.00
1986	59.96	.00	.20	6.58	1.25	31.87	.00	100.00
1987	59.17	.00	.20	6.65	1.26	32.41	.15	100.00
1988	58.17	.00	.22	7.32	1.39	32.44	.31	100.00
1989	57.13	.00	.24	7.98	1.51	32.52	.46	100.00
1990	56.00	.00	.26	8.63	1.64	32.70	.62	100.00
1991	54.71	.00	.27	9.01	1.71	33.36	.77	100.00
1992	53.75	.00	.28	9.53	1.81	33.52	.94	100.00
1993	53.05	.00	.29	9.89	1.88	33.63	1.10	100.00
1994	52.67	.00	.30	9.97	1.89	33.74	1.26	100.00
1995	52.38	.00	.30	9.99	1.90	33.86	1.42	100.00
1996	52.01	.00	.29	9.68	1.84	34.41	1.58	100.00
1997	51.82	.00	.29	9.58	1.82	34.56	1.77	100.00
1998	51.63	.00	.28	9.44	1.79	34.76	1.93	100.00
1999	51.45	.00	.28	9.30	1.76	34.95	2.10	100.00
2000	51.29	.00	.27	9.13	1.73	35.14	2.26	100.00

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

The share of total energy provided by natural gas on the mainland as reported in Table 3.6 is forecast to drop gradually from 57.8 percent in 1981 to 51.3 percent by the year 2000 in reflection of an increased share for electricity intensive multiple dwelling units in the total housing stock as well as some displacement by renewables. In spite of this reduced share however, natural gas requirements are forecast to increase from 56.0 petajoules in 1981 to 64.5 petajoules in 1990 and 68.8 petajoules in the year 2000. This represents an average annual growth rate of 1.6 percent between 1981 and 1990, and 0.7 percent between 1990 and 2000.

Electricity's share on the Mainland is forecast to increase from 26.8 percent in 1981 to 35.1 percent in 2000. This increase is attributable in part to the lower price increases which occurred during the early 1980's and the increasing proportion of the housing stock represented by electricity-intensive multiple dwellings. Electricity requirements maintain the highest growth rate among fuels, increasing from about 26.0 petajoules in 1981 to 37.7 petajoules in 1990 and 47.2 petajoules in the year 2000. Between 1981 and the year 2000 this equates to an average annual growth rate of 3.2 percent.

The consumption of refined petroleum products decreases between 1981 and 1990 as consumers respond to the major price increases incurred during the early 1980's. In the 1990's however, the demand for refined petroleum products increases at an average annual rate of 2.1 percent as oil price increases moderate relative to other fuels. As previously noted, this oil demand does not include diesel fuel oil.

3.3.2 Vancouver Island

Energy requirements for Vancouver Island are shown in Table 3.7. The total requirements on the Island are expected to increase from a level of 17.2 PJ in 1981 to 23.6 PJ by 2000 indicating an annual average rate of 1.7 percent.

Over the forecast period both oil and electricity are expected to experience a decline in their respective market shares. The decline in these fuel shares is primarily attributable to the extension of natural gas service to Vancouver Island and the changes in relative fuel prices which underly this forecast.

The share of natural gas was estimated exogenously by adjusting the oil and electricity shares determined by the energy model. As stated earlier, these adjustments to oil and electricity shares reflect the displacements in oil and electricity demand estimated in a staff study of natural gas supply to Vancouver Island.[9] Based on these adjustments, approximately 2.1 petajoules (13 percent) of the residential energy requirements on Vancouver Island are estimated to be provided by natural gas in 1986, increasing to about 9.6 petajoules (or 41 percent) by 2000.

With the availability of natural gas on the Island, the demand for refined petroleum products is expected to decline from 8.5 petajoules in 1981 to about 3.4 petajoules by 2000. Requirements for electricity, however, are forecast to increase but at a relatively slower rate of 1.1 per annum from 7.7 petajoules in 1981 to 9.5 petajoules in 2000.

Aside from the conventional fuels, renewables are also expected to contribute about 3.3 percent of the residential energy demand on Vancouver Island.

---

[9] Op. cit. p. 3-3.

TABLE 3.7

VANCOUVER ISLAND RESIDENTIAL SECTOR
ENERGY REQUIREMENTS

(PETAJOULES)

YEAR	NATURAL GAS	COAL AND COKE	HEAVY FUEL OIL	LIGHT FUEL OIL	L.P.G.	ELECT.	RENEWABLE ENERGY	TOTAL REQTS
1978	.000	.007	.074	9.085	.629	6.518	.000	16.313
1979	.000	.003	.128	9.282	.665	6.791	.000	16.869
1980	.000	.001	.166	8.873	.681	7.171	.000	16.892
1981	.000	.219	.139	8.452	.720	7.696	.000	17.226
1982	.000	.000	.072	8.429	.707	7.769	.000	16.977
1983	.000	.000	.070	8.179	.686	8.143	.000	17.078
1984	.000	.000	.064	7.547	.633	8.716	.000	16.960
1985	.000	.000	.061	7.155	.600	9.215	.000	17.031
1986	2.181	.000	.044	5.197	.436	9.274	.043	17.175
1987	3.271	.000	.038	4.517	.379	9.196	.073	17.474
1988	4.420	.000	.034	3.973	.333	9.110	.120	17.990
1989	5.623	.000	.029	3.406	.286	9.045	.169	18.558
1990	6.876	.000	.024	2.782	.233	8.997	.205	19.117
1991	6.953	.000	.024	2.875	.241	9.002	.259	19.354
1992	7.336	.000	.025	2.978	.250	9.003	.315	19.907
1993	7.721	.000	.026	3.079	.258	8.985	.356	20.425
1994	8.116	.000	.027	3.158	.265	8.978	.416	20.960
1995	8.521	.000	.027	3.225	.271	8.973	.478	21.495
1996	8.547	.000	.028	3.278	.275	9.070	.525	21.723
1997	8.809	.000	.028	3.332	.280	9.174	.592	22.215
1998	9.071	.000	.029	3.363	.282	9.286	.661	22.692
1999	9.340	.000	.029	3.386	.284	9.405	.714	23.158
2000	9.605	.000	.029	3.395	.285	9.517	.787	23.618

ANNUAL GROWTH RATES

1981-1990	.00	.00	¯17.73	¯11.62	¯11.78	1.75	.00	1.16
1990-2000	3.40	.00	1.91	2.01	2.03	.56	14.38	2.14
1981-2000	.00	.00	¯7.92	¯4.69	¯4.76	1.12	.00	1.67

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,

JUNE 1984

TABLE 3.8

VANCOUVER ISLAND RESIDENTIAL SECTOR
MARKET SHARES

(INPUT JOULES ; PERCENT)

YEAR	NATURAL GAS	COAL AND COKE	HEAVY FUEL OIL	LIGHT FUEL OIL	L.P.G.	ELECT.	RENEWABLE ENERGY	TOTAL REQTS
1978	.00	.04	.45	55.69	3.86	39.96	.00	100.00
1979	.00	.02	.76	55.02	3.94	40.26	.00	100.00
1980	.00	.01	.98	52.53	4.03	42.45	.00	100.00
1981	.00	1.27	.81	49.07	4.18	44.68	.00	100.00
1982	.00	.00	.42	49.65	4.16	45.76	.00	100.00
1983	.00	.00	.41	47.89	4.02	47.68	.00	100.00
1984	.00	.00	.38	44.50	3.73	51.39	.00	100.00
1985	.00	.00	.36	42.01	3.52	54.11	.00	100.00
1986	12.70	.00	.26	30.26	2.54	54.00	.25	100.00
1987	18.72	.00	.22	25.85	2.17	52.63	.42	100.00
1988	24.57	.00	.19	22.08	1.85	50.64	.67	100.00
1989	30.30	.00	.16	18.35	1.54	48.74	.91	100.00
1990	35.97	.00	.13	14.55	1.22	47.06	1.07	100.00
1991	35.93	.00	.12	14.85	1.25	46.51	1.34	100.00
1992	36.85	.00	.13	14.96	1.26	45.23	1.58	100.00
1993	37.80	.00	.13	15.07	1.26	43.99	1.74	100.00
1994	38.72	.00	.13	15.07	1.26	42.83	1.98	100.00
1995	39.64	.00	.13	15.00	1.26	41.74	2.23	100.00
1996	39.34	.00	.13	15.09	1.27	41.75	2.42	100.00
1997	39.65	.00	.13	15.00	1.26	41.30	2.67	100.00
1998	39.97	.00	.13	14.82	1.24	40.92	2.91	100.00
1999	40.33	.00	.13	14.62	1.23	40.61	3.08	100.00
2000	40.67	.00	.12	14.37	1.21	40.30	3.33	100.00

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

CHAPTER 4

COMMERCIAL SECTOR

4.0 Introduction

The commercial sector is defined to encompass those businesses included in the following sectors of the economy: finance, insurance and real estate, retail and wholesale trade, transportation and communication, private and business services and public administration. The latter category includes all levels of government, schools, universities and health services. Unlike the definition followed in the Ministry's 1981 forecast, the commercial sector does not include fuel requirements for construction activity (these have been included in the other industrial category), and agriculture (these have been included in the residential requirements except for motor gasoline and motive related diesel fuel use which are counted in the road sector). In addition, energy requirements for apartments have been included in the residential sector.

In the past, heavy fuel oil, diesel fuel, light fuel oil, kerosene, stove oil, liquefied petroleum gases, electricity and natural gas have been the predominant fuels used in the commercial sector.[1] Some coal was also used, but quantities became so small that Statistics Canada discontinued reporting them by 1975. However, it is recognized that very small amounts are still used.

Throughout the forecast, refined petroleum products are grouped together and referred to as either RPP's or Oil. This definition encompasses heavy fuel oil, diesel fuel oil, light fuel oil, kerosene, stove oil and liquefied petroleum gases.

---

[1] Some requirements for the B.C. Ferry System may have also been included in the estimates by Statistics Canada. However the information was too incomplete to separate these requirements out.

The energy requirements forecast is presented for the period 1982 to the year 2000. Section 4.1 presents an historical overview of the composition of the commercial sector and a profile of the fuels used. A forecast of commercial sector economic activity at the sub-sector level is contained in Section 4.2 and the energy and fuels requirements forecast is reported in Section 4.3.

4.1 Historical Profile

Economic Activity

Economic growth in the commercial sector over the previous two decades was stimulated by a substantial expansion in retail floor space - particularly for large shopping centres. During this period, as well, the increase in general economic activity resulted in a significant demand for commercial office space to accomodate such activities as finance, insurance, real estate, dental and private medical services. Further, B.C. emerged as a popular tourist location, fostering a substantial investment in the tourist accomodation and service industry. Numerous schools, colleges, hospitals and one major new university (Simon Fraser) were constructed as well.

In total, commercial sector GDP outpaced that of the whole economy, particularly in the last decade. Between 1970 and 1980, for example, commercial sector GDP grew at an average annual rate of 5.5 percent whereas that for the total economy averaged 5.3 percent. Consequently, commercial sector activity, as a proportion of total economic activity, rose from about 62 percent in 1970 to almost 64 percent by 1980.

Table 4.1 indicates that this growth was fairly broadly based with transportation, communication and storage leading the way with an average annual rate of 6.7 percent. In the latter 10 years, however, growth in this subsector dropped to 5.6% p.a. and community, business and personal services (including tourism) which grew at an average annual rate of 5.8 percent became the focus of rapid commercial growth. Over the entire period, public administration and Finance Insurance and Real Estate had the slowest growth rates, amounting to only 4.3 percent annually.

Table 4.1

Commercial Sector GDP: 1961 - 1981

(1971 dollars)

				AAR	
	1961	1971	1981	1981/1961	1981/1971
Public Administration	379	623	877	4.3	3.5
Transportation, Communication & Storage	485	1036	1789	6.7	5.6
Retail/Wholesale Trade	631	1181	1951	5.8	5.1
Finance, Insurance and Real Estate	688	1143	1556	4.2	3.1
Community, Business and Personal Services	990	1762	3098	5.9	5.8
Total Commercial	3173	5745	9271	5.5	4.9

Energy Consumption

In terms of energy requirements, the previous two decades marked a period in which growth and those factors underlying that growth underwent a dramatic change. During the sixties, economic growth in the commercial sector averaged 6.1 percent annually but declined to 4.9 percent between 1971 and 1981.

As well, real energy prices declined during the sixties (primarily electricity and natural gas) but increased during the seventies. In light of these factors, total energy requirements growth was stronger in the sixties, averaging 11.4 percent per annum, than in the seventies when it averaged only 3.0 percent (see Table 4.2).

All fuel types experienced a dramatic decline in growth rates but most notably, the average annual growth rate for natural gas dropped from 26.2 percent during the sixties to 5.6 percent during the seventies. The average annual growth rate for electricity dropped from 11.8 to 7.4 percent.

Despite these reduced growth rates, both fuels increased their shares of the market at the expense of oil. For the most part, this reflected a change in relative prices which saw the real price of light fuel oil, in response to the world oil crisis of 1973, grow at an average annual rate of 5.9 percent between 1970 and 1980. Natural gas requirements growth also reflected larger market areas brought about by extensions to the pipeline distribution system.

At the subsector level, detailed historical energy use data is not readily available except for some survey information gathered by the Ministry for some recent years. The results for 1979, as reported in Table 4.3 suggest that the public administration subsector, while contributing only 10.4 percent to the commercial GDP, consumed about 23 percent of the commercial energy.[2] These surveys indicated that virtually

---

[2] It should be noted that Statistics Canada estimated that for 1981, the public administration subsector consumed closer to 15 percent of the total energy in the commercial sector. A word of caution is in order however since it is unclear whether the definition of "public administration" is the same.

TABLE 4.2

HISTORICAL COMMERCIAL SECTOR ENERGY REQUIREMENTS

(PETAJOULES)

YEAR	NATURAL GAS	HEAVY FUEL OIL	LIGHT FUEL OIL	L.P.G.	DIESEL FUEL OIL	ELECT.	TOTAL REQTS
1961	1.872	7.665	3.670	.657	1.813	4.695	20.371
1962	2.301	7.744	3.184	1.244	2.548	5.033	22.055
1963	3.031	7.112	2.562	1.512	1.802	5.252	21.272
1964	3.610	8.242	5.045	1.651	1.971	7.757	28.277
1965	4.303	9.032	6.002	1.887	2.128	8.099	31.451
1966	7.966	8.055	7.213	2.680	.949	9.262	36.126
1967	10.389	9.621	7.803	1.971	2.268	9.502	41.554
1968	12.095	7.043	5.709	2.199	2.502	10.146	39.693
1969	14.702	11.949	7.345	3.114	3.425	11.997	52.531
1970	16.191	10.911	8.018	3.147	3.396	12.946	54.609
1971	19.134	10.187	8.403	3.971	4.103	14.291	60.088
1972	22.869	10.578	9.958	3.390	4.289	16.122	67.206
1973	23.325	5.766	8.701	3.352	6.439	19.098	66.682
1974	24.876	6.747	9.231	3.423	6.899	21.520	72.696
1975	27.579	5.964	10.794	3.371	6.854	21.381	75.942
1976	29.806	5.240	10.179	3.096	7.105	26.977	82.403
1977	29.687	5.178	9.362	3.039	6.249	24.898	78.413
1978	30.861	2.795	7.199	2.933	5.418	25.054	74.260
1979	33.123	3.487	8.020	2.820	4.217	28.340	80.007
1980	33.624	3.980	5.995	3.416	4.987	30.267	82.269
1981	33.227	5.229	5.049	3.100	5.059	29.231	80.895

ANNUAL GROWTH RATES

1961-1971	26.17	2.89	8.64	19.72	8.51	11.77	11.42
1971-1981	5.67	-6.45	-4.97	-2.45	2.12	7.42	3.02

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

all commercial diesel fuel was consumed in the public administration subsector and that commercial heavy fuel oil was consumed principally by schools and hospitals. Also some very small amounts of coal which continue to be consumed were identified as being requirements for hospitals.

4.2 Forecast Period Assumptions

Economic Growth

In retrospect, the previous two decades may well be viewed as a golden age when judged by economic performance in the commercial sector. Although the current recession is abating and economic activity is improving, commercial sector GDP is not expected to return to the lofty rates of growth experienced during the sixties and seventies. Indeed, it is anticipated that commercial sector GDP will average only 2.1 percent annually during the eighties. For the most part, this reflects a weakened consumer confidence brought on by continued high real interest rates, unemployment and restraint in the public administration subsector.

Table 4.3
Comparison of Economic Activity with Energy Consumption in the Commercial Sector - 1979

	Economic Activity*		Energy Consumption**	
	Millions of 1971 dollars	Percent	Petajoules	Percent
Public Admin.	923	10.4	16.3	23.0
Trans., Comm. and Storage	1685	89.6	53.0	74.9
Wholesale Trade	748			
Retail Trade	1053			
F.I.R.E.	1545			
Community Bus. and Personal Services	2910			
Other			1.5	2.1
Total Commercial	8864	100.0	70.8	100.0

* "British Columbia Economic Accounts 1961-1980," Ministry of Industry and Small Business Development.

** "British Columbia Energy Supply and Requirements Forecast 1980-1995," Ministry of Energy, Mines and Petroleum Resources, April 1981. Table 3.1A (Excludes agriculture and construction).

Over the longer forecast period to the year 2000, economic activity in the commercial sector is anticipated to grow at an average annual rate of 3.2 percent with the strongest growth centered in the community, business and personal services subsector. Growth in this subsector, stimulated by tourism activity generated by EXPO 86, averages 3.8 percent annually (see Table 4.4) in the forecast period.

In light of government restraint, growth is anticipated to be weakest in the public administration subsector where it averages only 0.75 percent annually between 1981 and 1990. As well, the weak economic performance for 1983 and the outlook for 1984 has brought about an excess of retail floor- space. This is anticipated to continue for some time - particularly on Vancouver Island. Trade is expected to grow at an average annual rate of only 2.2 percent annually between 1981 and 1990 and at 3.0 percent annually for the forecast period.

4.3 Total Energy and Fuel Requirements Forecast

Commercial sector requirements were forecast separately for the mainland and Vancouver Island. Both forecasts draw on a top-down approach[3] relating commercial energy requirements and fuel shares to commercial sector gross domestic product (GDP) and energy prices for electricity, natural gas and refined petroleum products (RPP's).

---

[3] For detailed methodology refer to "The B.C. Energy Demand Forecasting and Planning Model," Staff Paper, March 1983.

TABLE 4.4

DETAILS OF COMMERCIAL GDP FORECAST

(MILLIONS OF 1971 DOLLARS)

YEAR	F,I,R,E,	TRADE	T,C,S,	SERVICE	PUB,ADMIN,	TOTAL
1978	1,629	1,622	1,539	2,736	930	8,456
1979	1,545	1,801	1,685	2,910	923	8,864
1980	1,560	1,912	1,755	3,035	917	9,179
1981	1,556	1,951	1,789	3,098	877	9,271
1982	1,509	1,775	1,574	3,005	877	8,741
1983	1,523	1,792	1,589	3,063	859	8,828
1984	1,576	1,854	1,636	3,123	850	9,039
1985	1,639	1,946	1,701	3,232	858	9,377
1986	1,683	2,008	1,747	3,318	867	9,623
1987	1,716	2,068	1,816	3,417	876	9,893
1988	1,790	2,157	1,899	3,565	884	10,296
1989	1,875	2,255	1,985	3,742	911	10,768
1990	1,955	2,363	2,059	3,936	938	11,251
1991	2,033	2,453	2,148	4,125	966	11,725
1992	2,120	2,552	2,246	4,309	995	12,222
1993	2,213	2,655	2,348	4,524	1,025	12,765
1994	2,308	2,761	2,453	4,752	1,056	13,331
1995	2,402	2,864	2,556	4,980	1,088	13,889
1996	2,495	2,977	2,663	5,226	1,120	14,482
1997	2,588	3,088	2,772	5,480	1,154	15,082
1998	2,676	3,192	2,876	5,739	1,189	15,672
1999	2,770	3,302	2,984	6,014	1,224	16,293
2000	2,859	3,409	3,093	6,298	1,261	16,921

ANNUAL GROWTH RATES

1981-1990	2.57	2.15	1.57	2.70	.75	2.17
1990-2000	3.88	3.74	4.15	4.81	3.00	4.17
1981-2000	3.25	2.98	2.92	3.81	1.93	3.22

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

In previous Ministry forecasts, energy requirements in the commercial sector embodied conservation factors which had been applied exogenously through explicit assumptions with regard to the employment of newer more energy efficient technology to meet incremental requirements and the retrofitting of existing loads. In terms of the forecasting methodology followed here, it has been assumed that the estimated price elasticities sufficiently capture the effects of energy conservation since energy prices factor heavily in determining investments in the new energy efficient technologies. It should be noted that energy conservation, which became an important issue following the energy crisis of 1973, has largely been in response to real energy price increases.

In general, the forecast outlook for the next decade suggests that the slower rates of economic growth when coupled with rising real energy prices lead to much slower rates of growth for energy requirements than in the previous decade. Through the nineties, as real price increases moderate, stronger economic growth will induce higher rates of energy requirements growth.

For the Province as a whole, it is anticipated that total commercial sector energy requirements will grow at an average annual rate of 1.9 percent between 1981 and the year 2000 (see Table 4.5). Electricity requirements are expected to grow at an annual average rate of 2.5 percent while those for natural gas average 2.6 percent.

Table 4.6 shows the share of each fuel on a provincial basis for the commercial sector. It is apparent that oil will continue to be displaced by electricity and natural gas throughout the forecast period. Most of the increase in the share of natural gas is attributable to the commencement of natural gas service on Vancouver Island in 1986. A more complete analysis of the requirements forecast is detailed below.

TABLE 4.5

PROVINCIAL COMMERCIAL SECTOR
ENERGY REQUIREMENTS

(PETAJOULES)

YEAR	NATURAL GAS	HEAVY FUEL OIL	LIGHT FUEL OIL	DIESEL FUEL OIL	L.P.G.	ELECT.	TOTAL REQTS
1978	30.861	2.795	7.199	5.418	2.933	25.054	74.260
1979	33.123	3.487	8.020	4.217	2.820	28.340	80.007
1980	33.624	3.980	5.995	4.987	3.416	30.267	82.269
1981	33.227	5.229	5.049	5.059	3.100	29.231	80.895
1982	34.412	3.410	5.377	5.504	3.265	30.085	82.053
1983	33.866	4.286	3.879	3.603	2.505	30.448	78.587
1984	33.814	4.057	3.692	3.447	2.392	30.684	78.086
1985	34.039	4.025	3.675	3.457	2.385	31.014	78.595
1986	35.622	3.796	3.065	3.437	1.846	31.428	79.194
1987	36.891	3.709	2.714	3.388	1.521	31.862	80.085
1988	37.475	3.784	2.720	3.498	1.503	32.416	81.396
1989	38.066	3.839	2.701	3.592	1.467	33.139	82.804
1990	38.667	3.893	2.677	3.685	1.425	33.939	84.286
1991	39.374	3.997	2.735	3.830	1.449	34.744	86.129
1992	40.458	4.109	2.775	3.984	1.452	35.585	88.363
1993	41.672	4.266	2.884	4.187	1.511	36.483	91.003
1994	43.100	4.430	3.001	4.400	1.576	37.631	94.138
1995	44.706	4.592	3.107	4.616	1.629	38.915	97.565
1996	46.403	4.757	3.216	4.839	1.685	40.321	101.221
1997	48.111	4.913	3.319	5.056	1.739	41.811	104.949
1998	49.829	5.054	3.407	5.262	1.781	43.336	108.669
1999	51.566	5.194	3.497	5.469	1.826	44.913	112.465
2000	53.343	5.330	3.579	5.677	1.864	46.518	116.311

ANNUAL GROWTH RATES

1981-1990	1.70	¯3.23	¯6.81	¯3.46	¯8.27	1.67	.46
1990-2000	3.27	3.19	2.95	4.42	2.72	3.20	3.27
1981-2000	2.52	.10	¯1.79	.61	¯2.64	2.48	1.93

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

TABLE 4.6

PROVINCIAL COMMERCIAL SECTOR
MARKET SHARES

(INPUT JOULES ; PERCENT)

YEAR	NATURAL GAS	HEAVY FUEL OIL	LIGHT FUEL OIL	DIESEL FUEL OIL	L.P.G.	ELECT.	TOTAL REQTS
1978	41.56	3.76	9.69	7.30	3.95	33.74	100.00
1979	41.40	4.36	10.02	5.27	3.52	35.42	100.00
1980	40.87	4.84	7.29	6.06	4.15	36.79	100.00
1981	41.07	6.46	6.24	6.25	3.83	36.13	100.00
1982	41.94	4.16	6.55	6.71	3.98	36.67	100.00
1983	43.09	5.45	4.94	4.58	3.19	38.74	100.00
1984	43.30	5.20	4.73	4.41	3.06	39.30	100.00
1985	43.31	5.12	4.68	4.40	3.03	39.46	100.00
1986	44.98	4.79	3.87	4.34	2.33	39.68	100.00
1987	46.06	4.63	3.39	4.23	1.90	39.79	100.00
1988	46.04	4.65	3.34	4.30	1.85	39.83	100.00
1989	45.97	4.64	3.26	4.34	1.77	40.02	100.00
1990	45.88	4.62	3.18	4.37	1.69	40.27	100.00
1991	45.72	4.64	3.18	4.45	1.68	40.34	100.00
1992	45.79	4.65	3.14	4.51	1.64	40.27	100.00
1993	45.79	4.69	3.17	4.60	1.66	40.09	100.00
1994	45.78	4.71	3.19	4.67	1.67	39.97	100.00
1995	45.82	4.71	3.18	4.73	1.67	39.89	100.00
1996	45.84	4.70	3.18	4.78	1.66	39.83	100.00
1997	45.84	4.68	3.16	4.82	1.66	39.84	100.00
1998	45.85	4.65	3.14	4.84	1.64	39.88	100.00
1999	45.85	4.62	3.11	4.86	1.62	39.94	100.00
2000	45.86	4.58	3.08	4.88	1.60	39.99	100.00

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

4.3.1 Mainland

Over the forecast period, it is anticipated that the share of RPP's will decline from 18.3 percent of total commercial energy in 1981 to about 14.4 percent by the year 2000 (Table 4.7). Electricity's share increases from its 1981 value of 35.8 percent to about 38.4 percent in 1984 and remains almost constant thereafter, while that for natural gas increases during the early eighties but returns to its 1982 value by the year 2000.

For the most part, changes to the fuel shares in the early eighties reflect the rapid increases in oil prices through the 1979 to 1981 period. Real light fuel oil prices, for example, increased at an average annual rate of 19.4 percent. The share of RPP's is anticipated to continue declining through to 1985 as these past increases in real oil prices continue to induce adjustment away from oil.

Within the RPP group, the share of diesel fuel was determined separately so as to reflect historical patterns. Diesel fuel, for the most part, is used in remoter areas of the Province where fewer substitutes are available.[4] Thus it does not respond directly to changes in relative energy prices as do other RPP's. The shares of the remaining products were set at their most recent historical values after diesel requirements had been determined.

---

[4] Ministry research indicates that diesel fuel is predominantly used in the public administration subsector for government camps, schools and hospitals. Another reason for treating diesel fuel separately is that some requirements for the B.C. Ferry system may have also been included in the estimate by Statistics Canada. However, information was too incomplete to separate these requirements out.

TABLE 4.7

MAINLAND COMMERCIAL SECTOR
MARKET SHARES

(INPUT JOULES ; PERCENT)

YEAR	NATURAL GAS	HEAVY FUEL OIL	LIGHT FUEL OIL	DIESEL FUEL OIL	L,P,G,	ELECT,	TOTAL REQTS
1978	47.27	3.21	7.39	7.16	2.28	32.69	100.00
1979	46.87	3.70	7.60	5.16	2.07	34.61	100.00
1980	46.23	4.10	5.37	5.95	2.33	36.02	100.00
1981	46.13	5.44	4.28	6.58	1.94	35.63	100.00
1982	47.10	3.49	4.62	6.65	2.09	36.04	100.00
1983	48.45	5.02	2.96	4.32	1.34	37.92	100.00
1984	48.67	4.76	2.81	4.15	1.27	38.33	100.00
1985	48.70	4.69	2.76	4.14	1.25	38.45	100.00
1986	48.60	4.71	2.78	4.22	1.26	38.44	100.00
1987	48.43	4.79	2.82	4.34	1.28	38.35	100.00
1988	48.16	4.86	2.86	4.46	1.30	38.35	100.00
1989	47.81	4.90	2.89	4.56	1.31	38.53	100.00
1990	47.42	4.94	2.91	4.65	1.32	38.76	100.00
1991	47.16	4.98	2.94	4.75	1.33	38.85	100.00
1992	47.05	5.02	2.96	4.85	1.34	38.78	100.00
1993	47.04	5.06	2.98	4.94	1.35	38.63	100.00
1994	47.04	5.07	2.99	5.02	1.36	38.53	100.00
1995	47.05	5.07	2.99	5.08	1.36	38.45	100.00
1996	47.05	5.07	2.99	5.13	1.35	38.41	100.00
1997	47.05	5.04	2.97	5.17	1.35	38.42	100.00
1998	47.04	5.01	2.96	5.20	1.34	38.45	100.00
1999	47.03	4.98	2.93	5.22	1.33	38.51	100.00
2000	47.01	4.94	2.91	5.24	1.32	38.56	100.00

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

Beyond 1985, particularly in the 1990 to 2000 period, fuel shares remain relatively stable, reflecting the stability in relative fuel prices. There is a slight decline in the share of natural gas , however, reflecting the phase in of the average wholesale price for natural gas to the blended price of crude in Vancouver. On average, the price of natural gas in 1982 dollars is anticipated to increase at an annual rate of 0.83 percent between 1990 and the year 2000 while prices for RPP's increase at 0.75 percent and the price for electricity increases at 1.1 percent.

While further expansion of the natural gas distribution system is expected to continue and to encourage switching away from oil into natural gas, the effects moderate over the forecast period. Extensions will be primarily into rural residential areas where the volume of oil displaced per kilometre of new pipe installed is now much lower. Consequently, the impact on demand of future anticipated expansions in the distribution system for natural gas has been reduced.

In light of the trends foreseen for energy prices and economic activity, it is anticipated that total energy requirements will increase as indicated in Table 4.8 at an average annual rate of 0.4 percent between 1981 and 1990 and 3.3 percent between 1990 and the year 2000.

For the period 1981 to 1990, natural gas requirements grow at an average rate of only 0.8 percent annually. But with increased economic growth during the 1990's, natural gas requirements grow at an average annual rate of 3.2 percent, reaching 48 PJ by the year 2000. It is anticipated that

TABLE 4.8

MAINLAND COMMERCIAL SECTOR ENERGY REQUIREMENTS

(PETAJOULES)

YEAR	NATURAL GAS	HEAVY FUEL OIL	LIGHT FUEL OIL	DIESEL FUEL OIL	L.P.G.	ELECT.	TOTAL REQTS
1978	30.861	2.093	4.823	4.674	1.486	21.343	65.280
1979	33.123	2.612	5.371	3.649	1.461	24.460	70.676
1980	33.624	2.981	3.907	4.328	1.693	26.192	72.725
1981	33.227	3.916	3.082	4.737	1.397	25.663	72.022
1982	34.412	2.550	3.373	4.858	1.529	26.332	73.054
1983	33.866	3.509	2.068	3.019	.938	26.506	69.906
1984	33.814	3.309	1.951	2.886	.884	26.626	69.470
1985	34.039	3.277	1.932	2.895	.876	26.876	69.895
1986	34.240	3.320	1.957	2.972	.887	27.080	70.456
1987	34.453	3.406	2.008	3.088	.910	27.281	71.146
1988	34.718	3.502	2.065	3.217	.936	27.647	72.085
1989	34.985	3.587	2.115	3.336	.958	28.191	73.172
1990	35.265	3.673	2.165	3.460	.981	28.824	74.368
1991	35.797	3.779	2.228	3.604	1.010	29.487	75.905
1992	36.627	3.907	2.303	3.772	1.044	30.190	77.843
1993	37.702	4.054	2.390	3.962	1.083	30.959	80.150
1994	39.002	4.206	2.479	4.160	1.124	31.948	82.919
1995	40.446	4.362	2.572	4.367	1.166	33.057	85.970
1996	41.985	4.521	2.665	4.579	1.208	34.271	89.229
1997	43.548	4.669	2.753	4.786	1.248	35.559	92.563
1998	45.105	4.808	2.834	4.986	1.285	36.876	95.894
1999	46.694	4.943	2.914	5.186	1.321	38.238	99.296
2000	48.305	5.079	2.994	5.389	1.357	39.623	102.747
ANNUAL GROWTH RATES							
1981-1990	.66	¯.71	¯3.85	¯3.43	¯3.85	1.30	.36
1990-2000	3.20	3.29	3.30	4.53	3.30	3.23	3.29
1981-2000	1.99	1.38	¯.15	.68	¯.15	2.31	1.89

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES.

JUNE 1984

electricity requirements will reach about 40 PJ by the year 2000, growing at an average annual rate of almost 2.3 percent between 1981 and the year 2000.

After declining through the eighties, as a result of the rapid price increases in the 1979 to 1981 period, RPP's increase at rates generally approaching 3.3 percent through the nineties. For the most part, this is due to economic growth coupled with a stabilized market share. Diesel fuel however, enjoys a higher growth rate than other RPP's due to the special assumptions regarding its share.

4.3.2 Vancouver Island

As noted above, the forecast of energy requirements on Vancouver Island was developed using the B.C. Energy Forecasting and Planning Model. The major issue for Vancouver Island is the introduction of natural gas, assumed to commence in 1986. Prior to the introduction of gas, it is anticipated that the share of electricity will increase at the expense of oil as consumers continue to adjust in light of the rapid increases in real RPP prices over the 1979 to 1982 period.

Indeed, electricity's share has been increasing ever since the early sixties when it stood at about 17.0 percent of total energy on an input joule basis. By 1985, as indicated in Table 4.9, it will reach approximately 47.6 percent. As well, the share of RPP's which stood at approximately 60 percent in 1981, is expected to decline to about 52 percent by 1985, the year before natural gas service to Vancouver Island begins.

TABLE 4.9

VANCOUVER ISLAND COMMERCIAL SECTOR
MARKET SHARES

(INPUT JOULES ; PERCENT)

YEAR	NATURAL GAS	HEAVY FUEL OIL	LIGHT FUEL OIL	DIESEL FUEL OIL	L.P.G.	ELECT.	TOTAL REQTS
1978	.00	7.81	26.46	8.30	16.11	41.33	100.00
1979	.00	9.38	28.38	6.10	14.56	41.58	100.00
1980	.00	10.47	21.87	6.90	18.05	42.71	100.00
1981	.00	14.79	22.16	3.63	19.20	40.22	100.00
1982	.00	9.57	22.28	7.18	19.29	41.70	100.00
1983	.00	8.95	20.85	6.73	18.06	45.42	100.00
1984	.00	8.68	20.22	6.51	17.50	47.09	100.00
1985	.00	8.60	20.03	6.46	17.35	47.56	100.00
1986	15.83	5.44	12.68	5.32	10.98	49.76	100.00
1967	27.27	3.39	7.90	3.36	6.84	51.25	100.00
1988	29.61	3.02	7.03	3.03	6.09	51.22	100.00
1989	31.99	2.62	6.09	2.65	5.27	51.38	100.00
1990	34.30	2.22	5.16	2.27	4.47	51.58	100.00
1991	34.99	2.13	4.96	2.21	4.29	51.42	100.00
1992	36.42	1.92	4.49	2.02	3.88	51.28	100.00
1993	36.58	1.95	4.55	2.07	3.94	50.90	100.00
1994	36.53	2.00	4.65	2.14	4.03	50.66	100.00
1995	36.74	1.98	4.61	2.15	3.99	50.53	100.00
1996	36.84	1.97	4.60	2.16	3.98	50.46	100.00
1997	36.84	1.96	4.58	2.18	3.96	50.48	100.00
1998	36.98	1.93	4.49	2.16	3.88	50.57	100.00
1999	37.00	1.90	4.43	2.16	3.83	50.69	100.00
2000	37.15	1.85	4.31	2.12	3.73	50.84	100.00

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

Although some small amounts of electricity are used for heating purposes in the commercial sector, predominantly for tourist accommodation and small office space where seperate thermostatic control permits optimal energy management, it is expected that no electricity will be displaced by natural gas in view of the relatively high capital costs of retrofitting. Consequently, it has been assumed that all future heating requirements that would otherwise be met by RPP's for new commercial buildngs would be provided by natural gas.

In developing a forecast of natural gas capture rates, the Ministry has been guided by the natural gas forecast in the Natural Gas Supply to Vancouver Island Technical Report (VIGAS). While the initial share values for natural gas correspond to those in the VIGAS study, the values in the final years are lower, reflecting a lower potential displacement of oil as conservation through the 1982 to 1985 period will reduce oil's share. Morever, most of the potential displacement is achieved by 1992 after which only a modest increase in the share of natural gas is assumed. As on the mainland, the relatively constant shares reflect a period of stable relative energy prices.

Among the factors underlying the growth in total energy requirements for the commercial sector on Vancouver Island is economic activity. In the past, retail trade and public administration, which are relatively large energy users, accounted for much of the growth in commercial sector energy requirements. Indeed, as reported in table 4.3, public administration which only contributed 10.4 percent to provincial commercial economic activity accounted for as much as 23 percent of total provincial commercial sector energy requirements. The VIGAS study indicated that for Vancouver Island alone, public administration requirements made up about

TABLE 4.10

VANCOUVER ISLAND COMMERCIAL SECTOR
ENERGY REQUIREMENTS

(PETAJOULES)

YEAR	NATURAL GAS	HEAVY FUEL OIL	LIGHT FUEL OIL	DIESEL FUEL OIL	L,P,G,	ELECT,	TOTAL REQTS
1978	.000	.701	2.376	.745	1.447	3.711	8.980
1979	.000	.875	2.649	.569	1.359	3.881	9.333
1980	.000	.999	2.087	.659	1.723	4.076	9.544
1981	.000	1.312	1.966	.322	1.703	3.568	8.871
1982	.000	.861	2.005	.646	1.736	3.753	9.001
1983	.000	.777	1.810	.584	1.568	3.943	8.682
1984	.000	.748	1.742	.561	1.508	4.058	8.617
1985	.000	.748	1.743	.562	1.510	4.138	8.701
1986	1.383	.475	1.108	.465	.959	4.348	8.738
1987	2.436	.303	.706	.300	.611	4.581	8.939
1988	2.757	.281	.655	.282	.567	4.770	9.312
1989	3.081	.252	.587	.255	.508	4.948	9.631
1990	3.401	.220	.512	.225	.443	5.115	9.916
1991	3.577	.218	.507	.226	.439	5.257	10.224
1992	3.831	.202	.472	.212	.408	5.395	10.520
1993	3.970	.212	.494	.225	.428	5.524	10.853
1994	4.098	.224	.522	.240	.452	5.683	11.219
1995	4.260	.230	.535	.249	.463	5.859	11.596
1996	4.417	.236	.551	.259	.477	6.050	11.990
1997	4.563	.243	.567	.270	.491	6.252	12.386
1998	4.724	.246	.573	.276	.496	6.460	12.775
1999	4.872	.250	.583	.284	.505	6.675	13.169
2000	5.038	.251	.585	.288	.506	6.895	13.563
ANNUAL GROWTH RATES							
1981-1990	.00	-18.00	-13.89	-3.90	-13.90	4.08	1.25
1990-2000	4.01	1.33	1.34	2.50	1.34	3.03	3.18
1981-2000	.00	-8.34	-6.18	-.59	-6.19	3.53	2.26

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

28 percent of total commercial sector requirements. In light of the slow growth expected in retail trade, an excess of retail floor space is anticipated to continue for some time. As well, the dramatic slow down in government, as reported in Table 4.4, most of which will be centred on Vancouver Island, results in commercial sector GDP growth on Vancouver Island to be weighted heavily towards the less energy intensive subsectors. The elasticity between economic activity and total commercial sector energy requirements on Vancouver Island was reduced to reflect this development.

Total commercial energy requirements on Vancouver Island, as reported in Table 4.10, are anticipated to increase at an average annual rate of 2.3 percent between 1981 and the year 2000. In terms of individual fuels, it is forecast that electricity will grow at an average annual rate of 3.5 percent between 1981 and the year 2000. Requirements for refined petroleum products decline during the 1981 to 2000 period at average annual rates in the range of 0.6 to 8.3 percent. It is expected that natural gas requirements will increase from about 1.4 PJ in 1986 to 3.4 PJ by 1990. Between 1990 and the year 2000, natural gas requirements are expected to grow at an average annual rate of 4.0 percent, reaching approximately 5.0 petajoules by the year 2000.

CHAPTER 5

INDUSTRIAL SECTOR

5.0 Industrial Sector Overview

5.0.1 Introduction

This chapter outlines the forecast of energy requirements within the industrial sector in British Columbia. A general overview of the industrial sector will be presented first, followed by a review of each of the major industrial subsectors.

The industrial sector has been defined to be generally consistent with the categories employed by Statistics Canada in its publications Quarterly Report on Energy Supply - Demand in Canada (QRESD) and Consumption of Purchased Fuel and Electricity by the Manufacturing, Mining, Logging and Electric Power Industries. The latter publication contains considerable detail on energy consumption for each of the 20 manufacturing industries, the mining and logging industries, and forms the major data source for the industrial sector. This data includes only purchased fuel and has been supplemented, where possible, with information regarding the consumption of non-purchased energy (pulping liquors, hog fuel, self-generated hydroelectricity). Fuels consumed by industry in generating electricity and the concomitant electricity production are not identified for each industry. Secondary electricity is taken to exclude electricity generated by industry by thermal means and other fuel consumption includes the fuel for generating electricity by industry.[1]

---

[1] This treatment differs from the Quarterly Report on Energy Supply-Demand in Canada, reflecting the lack of appropriate data at the subsector level.

For the purposes of the present forecast, the industrial sector has been divided into 10 components: pulp and paper, wood, primary metals, chemicals, non-metallic minerals, petroleum and coal products, petrochemicals, other manufacturing, mining and other industrial. The other manufacturing industry includes the food and beverage, metal fabrication, transportation equipment, printing and publication, machinery and a number of smaller industries. The other industrial sector includes principally the logging and construction activity.

The natural gas consumed as a feedstock for the production of petrochemicals and liquefied natural gas has been included in Chapter 7 as non-energy requirements, not as an industrial requirement. The manufacture of these products is discussed under the category of petrochemicals in this chapter. However, the consumption of electricity and RPP's in the manufacturing process is included in the requirements of the industrial sector.

5.0.2 Historical Profile

The industrial sector in British Columbia is heavily concentrated in the primary resource industries, principally forestry and mining. Table 5.0.1 presents the composition of the industrial sector from 1961 to 1980. In 1980, the forest related activity (primary forestry, wood, pulp and paper) accounted for 34 percent of the industrial gross domestic product (GDP), while the mining industry accounted for 7.5 percent. In addition, much of the remaining industrial activity is related to supporting the forestry and mining industry, with construction activity comprising 25.1 percent in 1980.

Table 5.0.1

Economic Activity in the Industrial Sector: GDP

	Millions of 1971 Dollars			Percent of Total	
	1961	1970	1980	1961	1980
Forestry (Primary)	158	272	394	9.8	9.0
Mining	131	257	329	8.1	7.5
-metals	91	127	186	5.6	4.2
-other	40	130	143	2.5	3.3
Manufacturing	1021	1633	2549	63.5	58.4
-wood	296	414	629	18.4	14.4
-pulp and paper	196	328	462	12.2	10.6
-primary metals	75	104	174	4.7	4.0
-chemicals	38	47	85	2.1	1.9
-non-metallics	20	49	108	1.2	2.5
-petroleum and coal	27	34	48	1.7	1.1
-food and beverage (including fish products)	187	241	296	11.6	6.8
-other	182	406	747	11.3	17.1
Construction	298	583	1095	18.5	25.1
Total Industrial	1609	2735	4367	100.0	100.0

Table 5.0.2 outlines the profile of 1980 energy consumption by each of the 10 categories mentioned above. A comparison of Tables 5.0.1 and 5.0.2 demonstrates the different levels of energy intensity associated with the different components of the industrial sector. In 1980, the pulp and paper industry consumed about 60 percent of the total industrial energy requirements while accounting for only 10.6 percent of gross domestic product (GDP). Similarly, the primary metals industry consumed 6.9 percent of energy and contributed 4.0 percent of economic activity.

The self-generation of fuels is of particular importance in the energy consumption of the pulp and paper, primary metals and wood products industries. In 1980, pulp liquors and hog fuel provided approximately 70 percent of the requirements of the pulp and paper industry whereas hog fuel also met 57 percent of the requirements of the wood products industry. As well, self-generated hydroelectricity accounted for 86.4 percent of energy consumption by primary metal producers.

5.0.3 Forecast Period Assumptions

Economic activity in the industrial sector[2] is forecast to increase at an average annual rate of 1.7 percent between 1980 and 1990, and 2.9 percent from 1990 to 2000, with gross domestic product increasing from 4.362 billion (1971) dollars in 1980 to 5.175 and 6.864 billion (1971) dollars in 1990 and

---

[2] Defined to include primary forestry, mining, manufacturing and construction activity from Table 2.6.

TABLE 5.0.2

1980 ENERGY CONSUMPTION PROFILE OF THE INDUSTRIAL SECTOR

(PETAJOULES)

	NATURAL GAS	COAL AND COKE	HEAVY FUEL OIL	LIGHT FUEL OIL	DIESEL FUEL OIL	L,P,G,	HOG FUEL	PULPING LIQUORS	ELECT,	SELF-GEN ELECTRICITY	TOTAL REQTS
MINING	4.36	.00	.63	.24	7.24	.27	.00	.00	9.70	.00	22.45
MANUFACTURING	65.06	.00	29.70	.70	4.18	1.33	73.21	129.07	36.33	28.38	367.96
PULP/PAPER	28.43	.00	25.80	.00	.72	.19	44.86	129.07	17.31	1.84	248.21
WOOD	10.55	.00	.18	.24	2.38	.94	28.35	.00	7.42	.00	50.06
PRIN, MET,	2.97	.00	.12	.06	.07	.01	.00	.00	.64	24.49	28.35
CHEMICALS	3.15	.00	.44	.06	.04	.00	.00	.00	5.82	2.05	11.57
NON-MET,	8.38	.00	2.62	.08	.51	.07	.00	.00	1.15	.00	12.82
PETR,/COAL	5.07	.00	.00	.00	.00	.00	.00	.00	1.08	.00	6.15
OTH, MANUF	6.51	.01	.54	.27	.46	.12	.00	.00	2.91	.00	10.82
OTHER INDUSTRIAL	.04	.00	.51	.75	19.93	.00	.00	.00	.12	.00	21.35
TOTAL INDUSTRIAL	69.46	.01	30.84	1.69	31.35	1.60	73.21	129.07	46.15	28.38	411.77

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

2000, respectively. The forest manufacturing (pulp and paper and wood products) industry's share of total industrial activity is forecast to decline from about 25 percent in 1980 to 18.4 percent in the year 2000. As well, primary forestry's share is forecast to decline from 9 percent to 7 percent. Mining's share of total industrial activity on the other hand, increases from 7.4 percent in 1980 to 8.8 percent in the year 2000. The details of industrial economic activity have been presented more fully in Table 2.6 of Chapter 2.

5.0.4 Total Energy and Fuel Requirements Forecast

Total energy requirements in the industrial sector, as reported in Table 5.0.3, are forecast to increase from 368.3 petajoules in 1981 to 508.8 petajoules in the year 2000 for an average annual growth rate of 1.8 percent between 1981 and 1990 and 1.6 percent between 1990 and 2000. Requirements in the eighties grow relatively rapidly as the industrial sector recovers from the recession of the early eighties and as anticipated industrial developments come on stream by 1990. Industrial requirements growth moderates significantly in the 1990's as the forest industry is constrained by the available resource and the economy moves from its dependence on natural resource development to the less energy intensive commercial and light manufacturing activities.

The share of natural gas as percent of total energy consumption in the industrial sector as reported in Table 5.0.4 declines from 17.9 percent in 1981 to 13.8 percent in the year 2000 as the share of total energy met by wood waste (hog fuel, pulping liquor) and coal increases from 46.6 percent in 1981 to 50.6 percent by the year 2000. As well, electricity's (including

TABLE 5.0.3

INDUSTRIAL SECTOR ENERGY REQUIREMENTS

(PETAJOULES)

YEAR	NATURAL GAS	HEAVY FUEL OIL	COAL AND COKE	LIGHT FUEL OIL	L,P,G,	DIESEL FUEL OIL	HOG FUEL	PULPING LIQUORS	ELECT,	SELF-GEN ELECTRICITY	TOTAL REQTS
1978	62.308	37.820	.000	1.794	1.682	25.204	72.314	122.998	43.210	28.689	396.019
1979	66.664	39.494	.000	2.260	1.712	27.334	72.491	118.113	44.869	27.831	400.768
1980	69.464	30.840	.010	1.695	1.605	31.348	73.211	129.066	46.152	28.378	411.769
1981	65.889	26.089	.010	1.572	1.226	28.883	64.303	107.161	44.582	28.617	368.332
1982	61.980	25.249	.009	1.501	1.161	27.117	65.115	109.469	44.321	28.315	364.237
1983	59.135	23.859	.009	1.519	1.182	28.125	77.661	112.746	46.836	28.961	380.033
1984	61.834	25.010	2.467	1.556	1.213	28.898	78.005	114.063	49.773	29.139	391.958
1985	62.305	24.845	3.743	1.629	1.266	30.759	81.425	113.533	51.859	29.324	400.688
1986	68.087	16.184	5.372	1.311	.790	30.318	77.559	109.359	50.288	29.324	388.592
1987	66.157	16.655	7.610	1.330	.803	30.688	79.861	110.150	50.364	30.901	394.519
1988	64.580	17.259	10.136	1.348	.818	31.590	83.775	113.837	54.032	30.901	408.276
1989	62.382	16.978	11.329	1.358	.816	31.942	90.313	116.366	54.389	30.901	416.774
1990	60.949	17.651	12.701	1.344	.795	34.466	92.480	118.956	52.589	40.621	432.552
1991	61.909	18.235	12.780	1.355	.806	36.790	95.674	121.549	53.940	40.621	443.659
1992	62.314	18.818	12.945	1.369	.819	38.750	97.035	120.947	55.369	40.621	448.987
1993	63.189	18.892	13.965	1.379	.823	39.278	100.202	122.255	56.948	40.621	457.552
1994	64.028	19.482	14.616	1.391	.839	39.719	100.289	121.766	58.718	40.621	461.469
1995	65.526	20.435	15.100	1.401	.852	40.114	102.062	125.963	59.507	40.621	471.581
1996	67.210	19.724	15.361	1.410	.863	40.505	103.930	128.148	60.212	40.621	477.984
1997	68.311	20.225	16.633	1.433	.887	41.238	104.903	130.332	61.906	41.945	487.813
1998	69.369	20.701	16.867	1.442	.895	41.584	105.285	132.575	62.621	41.945	493.284
1999	70.157	21.095	17.108	1.451	.905	41.928	105.996	134.089	66.095	48.785	507.609
2000	70.411	21.100	17.319	1.458	.911	42.236	106.085	134.089	66.387	48.785	508.781
ANNUAL GROWTH RATES											
1981-1990	¯.86	¯4.25	121.24	¯1.73	¯4.70	1.98	4.12	1.17	1.85	3.97	1.80
1990-2000	1.45	1.80	3.15	.82	1.37	2.05	1.38	1.20	2.36	1.85	1.64
1981-2000	.35	¯1.11	48.06	¯.40	¯1.55	2.02	2.67	1.19	2.12	2.85	1.71

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

TABLE 5.0.4

PROVINCIAL INDUSTRIAL SECTOR
MARKET SHARES

(INPUT JOULES ; PERCENT)

YEAR	NATURAL GAS	HEAVY FUEL OIL	COAL AND COKE	LIGHT FUEL OIL	L.P.G.	DIESEL FUEL OIL	HOG FUEL	PULPING LIQUORS	ELECT.	SELF-GEN ELECTRICITY	TOTAL REQTS
1978	15.73	9.55	.00	.45	.42	6.36	18.26	31.06	10.91	7.24	100.00
1979	16.63	9.85	.00	.56	.43	6.82	18.09	29.47	11.20	6.94	100.00
1980	16.87	7.49	.00	.41	.39	7.61	17.78	31.34	11.21	6.89	100.00
1981	17.89	7.08	.00	.43	.33	7.84	17.46	29.09	12.10	7.77	100.00
1982	17.02	6.93	.00	.41	.32	7.44	17.88	30.05	12.17	7.77	100.00
1983	15.56	6.28	.00	.40	.31	7.40	20.44	29.67	12.32	7.62	100.00
1984	15.78	6.38	.63	.40	.31	7.37	19.90	29.10	12.70	7.43	100.00
1985	15.55	6.20	.93	.41	.32	7.68	20.32	28.33	12.94	7.32	100.00
1986	17.52	4.16	1.38	.34	.20	7.80	19.96	28.14	12.94	7.55	100.00
1987	16.77	4.22	1.93	.34	.20	7.78	20.24	27.92	12.77	7.83	100.00
1988	15.82	4.23	2.48	.33	.20	7.74	20.52	27.88	13.23	7.57	100.00
1989	14.97	4.07	2.72	.33	.20	7.66	21.67	27.92	13.05	7.41	100.00
1990	14.09	4.08	2.94	.31	.18	7.97	21.38	27.50	12.16	9.39	100.00
1991	13.95	4.11	2.88	.31	.18	8.29	21.56	27.40	12.16	9.16	100.00
1992	13.88	4.19	2.88	.30	.18	8.63	21.61	26.94	12.33	9.05	100.00
1993	13.81	4.13	3.05	.30	.18	8.58	21.90	26.72	12.45	8.88	100.00
1994	13.87	4.22	3.17	.30	.18	8.61	21.73	26.39	12.72	8.80	100.00
1995	13.89	4.33	3.20	.30	.18	8.51	21.64	26.71	12.62	8.61	100.00
1996	14.06	4.13	3.21	.29	.18	8.47	21.74	26.81	12.60	8.50	100.00
1997	14.00	4.15	3.41	.29	.18	8.45	21.50	26.72	12.69	8.60	100.00
1998	14.06	4.20	3.42	.29	.18	8.43	21.34	26.88	12.69	8.50	100.00
1999	13.82	4.16	3.37	.29	.18	8.26	20.88	26.42	13.02	9.61	100.00
2000	13.84	4.15	3.40	.29	.18	8.30	20.85	26.35	13.05	9.59	100.00

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

self-generation) share increases from 19.9 percent in 1981 to 22.6 percent in the year 2000. Oil's share falls from 15.7 percent in 1981 to 12.9 percent in the year 2000 as conservation and the reduction in heavy fuel oil with the commencement of natural gas service on Vancouver Island work to reduce the demand for oil products.

5.1 The Forestry Subsector

Introduction

The forestry subsector consists of the pulp and paper, wood products and primary forestry (logging) industries. For the purposes of this forecast however, logging has been excluded due to the lack of available comprehensive data. The energy requirements of the logging industry will be included within the "other industrial" category.[3]

In 1980, the forestry subsector accounted for approximately 72 percent of industrial sector energy requirements and 33 percent of total provincial secondary energy requirements, making it the largest single energy consumer in both the industrial sector and the province.

The pulp and paper industry was composed of 4 integrated newsprint mills, 15 kraft pulp mills, 4 paper mills and 1 mechanical pulp mill. These 24 mills consumed 248 petajoules of energy in 1980, or 60 percent of total industrial energy requirements. The wood products industry is composed of a large number of operations which vary significantly in size. These operations include saw mills, plywood and veneer mills, shake and shingle mills, particleboard plants and miscellaneous wood industries. In 1980, these operations consumed 50 petajoules of energy, amounting to 12.2 percent of total industrial energy requirements.

---

[3] The Statistics Canada publication on purchased fuels contains an estimate of fuel consumed by the logging industry from 1975 onwards. However, this estimate is significantly lower than the Ministry's estimates.

The production and energy requirements of the pulp and paper and wood products industries are examined together, reflecting the dependence which the pulp and paper industry has upon the wood products industry and the dependence which both have upon a common forestry resource. The wood products industry converts a large volume of timber into chips which are used by the pulp and paper industry in the production of pulp. Waste materials from the wood products industry are consumed by both the wood products and pulp and paper industries for energy in the form of hog fuel. Finally, a change in production levels or technologies of either industries may impinge upon the production of the other.

The methodology employed for ensuring consistency between the available forest resource, industry production forecasts and the production and consumption of hog fuel will be outlined below. This is followed by separate discussions of the two industries.

In the forestry subsector, it is necessary to ensure that the forecast of production of wood and paper products is consistent with the available raw materials and the industry's production technology. In ensuring this balance the Ministry first examined the wood products industry.

The analysis begins with a forecast of demand for wood products which would prevail in the absence of a shortage of available timber. Following discussions with the Ministry of Forests and members of the industry, the Ministry developed a set of "lumber recovery factors" to define the proportion of raw timber scaled in the field which is converted into finished product, wood chips, sawdust and shavings and losses. This set of factors has been estimated for both the Interior and the Coast regions and is discussed more fully in the Ministry's 1981 forecast. These factors are applied to the "demand determined" production forecast to determine the volume of scaled timber which would be required to allow this level of output.

Based upon an examination of the pulp and paper mills, the Ministry also developed a series of factors which define the volume of wood chips, sawdust and roundwood required for the production of each tonne of pulp production.[4] These factors have been developed for each of five regions of the province, and the factors have been modified over time to allow for greater utilization of sawdust digesters and the replacement of wood chips. An essentially "demand determined" production forecast was specified for the pulp and paper products and the resulting level of roundwood requirements was determined.

The timber requirements of the pulp and paper and wood products industries are aggregated by region and compared with the annual allowable cut which is available. Where there is not sufficient timber to satisfy the requirements of a region, a portion of the wood or pulp and paper production forecast is assumed to either occur in a region with a surplus or to be constrained. The wood products industry is assumed to bear the full impact of the constrained product.

---

[4] Roundwood is raw timber which is converted either to wood chips in the production of kraft or to stoneground pulp in the production of newsprint.

The lumber recovery factors are then applied to the feasible timber supply available to the wood products industry to determine the volume of finished product, wood chips, and sawdust and shavings which could be produced. The available wood chip and sawdust volumes are examined to determine whether there is sufficient wood fibre available to support the forecast of pulp and paper output set out above. If there are not sufficient quantities of wood chips or sawdust available in any region to meet a specified output level, it is assumed that transfers of fibre will occur such that a constraint upon total pulp and paper production can not occur in the presence of a surplus of wood chips in any region. If transfers of fibre are not able to support the total production level, the actual production forecast is correspondingly reduced.[5]

Through the mechanism outlined above, there is a consistency between industries and a balance in the demand and supply of fibre. Constrained timber production reduces the roundwood requirements for pulp production, thereby increasing the supply of timber available to the wood products industry. The mechanism is allowed to iterate until a convergent solution for both pulp and paper and wood production is obtained.

---

[5] The forecast allows for an increase in the consumption of sawdust in digesters, displacing wood chips, and as well assumes that a proportion of the chips required in thermomechanical pulp (TMP) and chemi-thermo-mechanical pulp production would be rendered from hardwood and decadent softwood stands, not included in the estimated annual allowable cut.

The supply of hog fuel available for consumption in both the pulp and paper and wood products industry is determined by adding the production of bark and the production of sawdust and shavings less the consumption of sawdust in the digesters. On the Coast, it has been estimated that bark accounts for about 13 percent of the volume of timber before barking.[6] In the Interior, it is about 11 percent. Estimated energy contents of 8.5 and 9.1 gigajoules per cubic metre (solid wood equivalent) for bark and 8.0 and 7.7 gigajoules per cubic metre for sawdust for the Coast and Interior, respectively, have been applied to the net production numbers to produce an estimate of the regional supply of hog fuel. The estimated hog fuel availability is consistent with the forecast of pulp and paper and wood production, and the total availability of fibre.

5.1.1 Pulp and Paper

5.1.1.1 Historical Profile

The 24 pulp and paper mills in British Columbia produce a range of products. The four large integrated mills on the Coast produce kraft and mechanical pulps which are transformed into finished newsprint and market kraft pulp products. Four sulfate kraft mills are located on the South Coast with an additional mill producing sulfite kraft. The Lower Mainland is the site of four paper product mills which produce a wide range of products. Eight sulfate kraft mills are located in the Interior with two additional mills on the North Coast. One refiner mechanical pulp producer is operating in the Interior and the small newsprint mill at Ocean Falls ceased operations in 1979. For the purpose of this forecast, the pulp and paper mills have been divided into five categories and production and energy consumption have been analyzed for each of these categories. Table 5.1.1 displays the mapping between individual mills and the broader mill aggregations. The Finlay Mill has been included in the Interior Kraft Mill category for confidentiality purposes, despite its being a refiner mechanical pulp operation.

---

[6] The annual allowable cut is specified in terms of merchantable timber and excludes the volume of bark.

In 1982, the Quesnel River Pulp Mill began operations producing two lines of thermo-mechanical pulp, and one of these lines has recently been upgraded to produce chemi-thermo-mechanical pulp.

Energy consumption varies significantly between mills according to the product manufactured and production technology employed. Table 5.1.2 displays the energy consumption profiles for the five mill aggregations identified above for the year 1980, and summarizes the major differences.

Kraft pulp mills require large volumes of energy to be converted to steam to meet the heat requirements of the pulping process. However, these mills produce and consume significant volumes of energy in the form of pulping liquors and hog fuel. Newsprint operations are highly electricity intensive, requiring electricity in the production of stoneground and thermo-mechanical pulps as well as in the operation of the newsprint machines.

For kraft mills, there are three major vehicles of energy consumption: recovery boilers, lime kilns and power boilers. The kraft pulping process produces pulping liquor which contains residual chemicals and dissolved wood fibre (lignin).

Table 5.1.1

Mill Categories for Forecasting Energy Requirements

1. Coastal Integrated Kraft/Newsprint Operations

   Crofton (BCFP)
   Elk Falls (Crown Zellerbach)
   Port Alberni (MacMillan-Bloedel)
   Powell River (MacMillan-Bloedel)

2. S. Coastal Kraft Mills

   Harmac (MacMillan-Bloedel)
   Port Alice (Western F.P.)
   Port Mellon (Canfor)
   Tahsis
   Woodfibre (Western F.P.)

3. Lower Mainland Paper Mills

   Annacis Island (MacMillan-Bloedel)
   Belkin
   New Westminster (Canfor)
   Scott Paper

4. Interior Kraft Mills*

   Cariboo
   Castlegar (B.C. Timber)
   Crestbrook
   Finlay Forest Industry**
   Intercontinental (Canfor)
   Kamloops (Weyerhaueser)
   Mackenzie (BCFP)
   Northwood
   Prince George (Canfor)

5. N. Coastal Kraft Mills

   Kitimat (Eurocan)
   Prince Rupert (B.C. Timber)

---

* Beginning in 1982, the West Fraser Mill at Quesnel is included in this group.

** Refiner mechanical pulp

TABLE 5.1.2

1980 PULP AND PAPER ENERGY REQUIREMENTS
(BY REGION)

(PETAJOULES)

REGION	NATURAL GAS	HEAVY FUEL OIL	L.P.G.	DIESEL FUEL OIL	HOG FUEL	PULPING LIQUORS	ELECT.	SELF-GEN ELECTRICITY	TOTAL REQTS
S, COAST NEWSPT	.00	14.14	.07	.21	17.39	30.39	9.47	1.74	73.40
S, COAST KRAFT	.00	9.84	.08	.06	10.01	33.02	1.75	.10	54.87
L, MAIN, PAPER	2.20	.14	.01	.04	.88	.00	.99	.00	4.26
INTERIOR KRAFT	18.14	.98	.01	.22	15.49	49.37	3.56	.00	87.78
N, COAST KRAFT	8.09	.69	.01	.19	1.09	16.29	1.53	.00	27.89
TOTAL	28.43	25.79	.19	.72	44.86	129.07	17.31	1.84	248.21

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

This liquor is burned in a recovery boiler to recover the chemicals from the liquor and the resulting heat is employed to generate steam for the mill operation. A small amount of fossil fuel is consumed in the recovery boiler. The lime kiln transforms some of the chemicals recovered from the pulping liquors into a form reuseable in the process, and is fired principally by natural gas or heavy fuel oil. The power boilers provide the incremental volume of steam required in the mill operation and are fired principally by hog fuel, natural gas and heavy fuel oil.

Kraft mills consume considerable volumes of hog fuel in generating steam as it is generally the least cost fuel and many mills produce hog fuel on site through chipping or associated wood product activities. Hog fuel is considered to be a waste product which must be burnt to generate heat or disposed of in land fills or bee-hive burners. Consequently the cost of hog fuel to a pulp mill is often only the cost of transport. Under current energy consumption patterns, there is a plentiful supply of hog fuel except on the South Coast where existing hog burning capacity can consume virtually all available hog fuel under full production. While there may be a significant surplus of hog fuel in the Interior overall, there may be locations where availability is limited due to the cost associated with transporting the fuel from the source.

The production of high pressure steam for meeting process steam needs of the kraft pulp mills allows the possibility of installing turbo-generators for the generation of electricity. Electricity is produced by reducing the pressure of steam by passing it through a turbo-generator. For a back-pressure turbine, the pressure is reduced to a level useable for the process and about 1.14 gigajoules of steam is charged to the production of 1.00 gigajoules of electricity, while for a condensing turbine the pressure is reduced to a level which is so low that the steam condensate must be sewered and about 3.37 gigajoules of steam must be charged to the generation of 1.00 gigajoules of electricity. A significant level of turbo-generator capacity has already been installed in British Columbia and there is some potential for further installations over the forecast period. These investments will be associated principally with new or existing hog fuel burning facilities.

The production of newsprint requires the processing of a mixture of kraft pulp with stoneground or mechanical pulp. The introduction of thermo-mechanical pulp (TMP) in displacing stoneground pulp has allowed producers to reduce the share of fibre comprised by kraft pulp. This phenomenon allows producers to employ existing fibre sources more efficiently but has also led to an increase in electricity requirements as TMP requires more electricity than does stoneground pulp.

5.1.1.2 Forecast Period Assumptions

The forecast of pulp and paper production has been prepared following an analysis of the demand for paper products as well as the ability of the industry to supply these output levels. The methodology for this analysis has been outlined above.

The lumber recovery factors for the manufacture of wood products are assumed to remain constant throughout the forecast period. Any gains realized through the incorporation of new technology in the manufacturing process is expected to be offset by the decreasing size of timber as first growth timber stands are depleted.[7]

---

[7] Proportionately less of a smaller diameter tree will find its way into the manufacture of finished product.

The forecast allows for an increase in the consumption of sawdust as furnish in the production of kraft pulp. By 1995, it is expected that sawdust will provide up to 10 percent of the total kraft pulp furnish, thereby modestly reducing the dependence of kraft production upon the availability of wood chips.

The increased development of thermo-mechanical pulp (TMP) and chemi-thermo-mechanical pulp (CTMP) production within the province is expected to have a substantial impact upon the industry. The assumptions which are made in the forecast with respect to this development will be outlined below and from the perspective of the impact of wood chip supplies upon production, it has been assumed that one half of the TMP and all of the CTMP fibre requirements would be rendered from hardwood or decadent softwood stands which would not be included in the definition of the annual allowable cut.

The proportion of pulp furnish in the production of newsprint represented by TMP is expected to increase sharply from about 14 percent in 1980 to 60 percent in 1995.[8] Incorporated in this shift is the introduction of the TMP lines at Powell River, Elk Falls and Crofton, and the assumption that the Port Alberni newsprint operation will be converted to use TMP for virtually all of its total pulp furnish requirements with a corresponding closure of its existing kraft pulp facilities.

---

[8] The increased utilization of TMP allows the manufacturer to reduce the quantity of kraft pulp in newsprint production.

The Quesnel River Pulp Mill has introduced the CTMP technology to British Columbia and it is likely that others will observe the experiences of this operation before undertaking a similar project. The CTMP technology presents a number of advantages to the industry. The high yield pulping technology converts about 90 percent of the input fibre into finished pulp while the kraft pulping process converts only about 50 percent. The capital requirements are significantly lower than those associated with a greenfield bleached kraft operation and the process is able to utilize some hardwoods and softwoods which would not otherwise be used by the wood products industry or other pulp operations.

The CTMP product has not as yet established a firm world market, as has kraft pulp, nor does British Columbia possess any attributes which would give the technology an advantage in British Columbia relative to other jurisdictions. In particular, much greater fibre potential exists in Alberta and in regions typified by more rapid forest regeneration, and British Columbia may be further from the final consumer than many producers, incurring greater transportation charges. The Ministry has assumed that in addition to the Quesnel River Pulp Mill, which is designed to produce about 450 tonnes per day, two additional CTMP mills, each producing 500 tonnes per day, will be constructed with the first to be in operation in 1992 and the second to commence operation in 1994.

The demand for pulp and paper products, in physical units, is forecast to increase at the rate of growth in GDP reflected in Table 2.6. Table 5.1.3 presents the resulting forecast of pulp and paper production. Newsprint production is forecast to increase from 1.25 million tonnes in 1982 to 1.45 million tonnes in 1990 and 1.76 million tonnes in 2000, reflecting the

TABLE 5.1.3

FORECAST OF PULP AND PAPER PRODUCTION

(MILLIONS OF TONNES)

YEAR	KRAFT PULP COAST	INTERIOR	TOTAL	NEWSPRINT	OTHER PRODUCTS	TOTAL
1978	2.347	1.695	4.043	1.326	.371	5.740
1979	2.192	1.682	3.874	1.282	.382	5.539
1980	2.305	1.807	4.112	1.358	.381	5.850
1981	1.961	1.469	3.429	1.216	.352	4.998
1982	1.727	1.744	3.470	1.252	.439	5.161
1983	1.928	1.691	3.619	1.361	.519	5.500
1984	1.979	1.680	3.659	1.397	.589	5.645
1985	1.972	1.668	3.640	1.392	.593	5.626
1986	1.907	1.598	3.505	1.346	.588	5.440
1987	1.919	1.610	3.530	1.355	.590	5.475
1988	1.977	1.673	3.649	1.396	.594	5.639
1989	2.016	1.715	3.732	1.424	.596	5.752
1990	2.057	1.759	3.816	1.452	.599	5.867
1991	2.098	1.804	3.902	1.481	.601	5.984
1992	2.161	1.705	3.865	1.525	.772	6.163
1993	2.174	1.823	3.996	1.572	.782	6.349
1994	2.220	1.746	3.966	1.619	.955	6.540
1995	2.250	1.858	4.108	1.667	.960	6.735
1996	2.265	1.916	4.181	1.692	.964	6.837
1997	2.280	1.975	4.255	1.717	.967	6.939
1998	2.295	2.033	4.328	1.743	.972	7.043
1999	2.306	2.073	4.378	1.761	.975	7.114
2000	2.306	2.073	4.378	1.761	.975	7.114
			ANNUAL GROWTH RATES			
1981-1990	.53	2.03	1.19	1.99	6.07	1.80
1990-2000	1.15	1.65	1.38	1.95	4.99	1.95
1981-2000	.86	1.83	1.29	1.97	5.50	1.88

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,

JUNE 1984

recent expansions in newsprint capacity. The other products indicated on Table 5.1.3 include the production from the four Lower Mainland paper mills, the Finlay Forest Industry Mill, the Quesnel River Pulp Mill and the two additional CTMP operations. By 2000, the production of CTMP amounts to 0.52 million tonnes.

The annual allowable cut has been held constant through the forecast period at 25.1 million cubic metres for the South Coast (Vancouver Forest District), 8.4 million cubic metres for the North Coast (Prince Rupert Forest District) and 41.2 million cubic metres for the remainder of the province. Consequently, the provincial supply of wood chips has been forecast to be fully utilized by 1992. When this constraint occurs, it has been assumed lumber production will be reduced as discussed later in the wood products industry section.

5.1.1.3 Total Energy and Fuel Requirements Forecast

The forecast of energy consumption in the pulp and paper sector has been based upon the methodology described in the Ministry's Staff Paper on Energy Demand Forecasting and Planning Model where total energy consumption, in output joules, is forecast as a function of pulp and paper production levels and energy prices. A forecast of the consumption of the "non-purchased" fuels, pulping liquors and hog fuel is specified based on production levels, historical patterns, hog fuel supplies and the expected investment in hog fuel burning facilities.

The forecast of electricity consumption is based on pulp and paper production levels, the mix of pulp furnish in the newsprint process and real electricity prices. The impact of cogeneration is introduced as a reduction in purchased electricity requirements, along with a net increase in total energy requirements reflecting the conversion efficiency of high pressure steam to electricity.

Those total energy requirements which are not met by the consumption of pulping liquors, hog fuel or electricity are met principally by the consumption of natural gas or heavy fuel oil, with liquefied petroleum gases and diesel fuel oil meeting mainly ancilliary requirements. The final forecast of fuel requirements is analyzed to ensure that sufficient fossil fuel would be available to operate the lime kilns and recovery boilers.

The flow in which the forecast is prepared is consistent with the way in which the energy consumption decision is made in a mill. Pulping liquors are generated in the production process and must be burnt to recover chemicals. Hog fuel generally represents the next least cost fuel and mills will tend to consume the maximum volume of hog fuel which is consistent with the available hog burning facilities and the steam flow requirements of the mill. Electricity requirements must be met by electricity purchases or the generation by hydro or thermal facilities. Natural gas and heavy fuel oil are burned in the lime kilns and power boilers and generally constitute the residual fuels which ensure that the total steam requirements of a mill are met.

The forecast of total energy requirements for the newsprint mills has been adjusted to reflect a structural change. The ratio of newsprint to total pulp and paper production had historically been useful in explaining the energy intensity of production because a large portion of the pulp furnish was slush kraft which required "double processing" (it undergoes essentially the same production process as market pulp plus the transformation to newsprint). Over the forecast period, there is a reduction in the production of kraft pulp and a shift towards TMP which requires lower levels of energy consumption per tonne of production. The ratio of newsprint to total production would suggest greater energy intensity while the technology would in fact be reducing consumption. The forecast results were adjusted to incorporate this effect.

Based on historical relationships, the production of pulping liquors has been tied to kraft pulp production. With the exception of the Harmac facility where the anticipated rebuild of a boiler is expected to improve its efficiency substantially, the efficiency with which recovery boilers convert the pulping liquor to heat is assumed to remain constant.

The forecast of hog fuel consumption has been prepared on a mill by mill basis as a function of the mills ability to burn hog fuel and the availability of sufficient fuel. Hog fuel supplies have been forecast separately for the South Coast, North Coast and Interior. The hog fuel supply/demand balance is examined in more detail in Chapter 10.

The demand for electricity is defined to include purchased electricity, self-generated hydroelectricity and electricity obtained through cogeneration. Electricity consumption per unit of output is forecast to be the same as that in the previous time period adjusted for the change in consumption patterns due to changes in real electricity prices and the mix of pulp furnish for the newsprint mills.

The mix of pulp furnish in the manufacture of newsprint is important for determining electricity requirements as the production of each pulp variety requires very different levels of electricity intensity. For the newsprint mills, kraft pulp production has been estimated to consume 3.0 gigajoules of electricity per tonne while stoneground and thermo-mechanical pulps have been estimated to consume about 5.9 and 7.8 gigajoules per tonne, respectively, in 1980. Newsprint processing of the pulps was estimated to require 1.8 gigajoules per tonne.

The impact of the CTMP mills upon energy requirements is introduced to the forecast exogenously. The production of CTMP is expected to require electricity requirements of 7.9 gigajoules per tonne and natural gas requirements of 4.2 gigajoules per tonne. By 1995, the CTMP mills are expected to consume 4.1 petajoules of electricity and 2.2 petajoules of natural gas.

Discussions with the industry have indicated that it is likely that two mills in the Interior will install turbogenerator capacity that will allow each to produce an average of 25 megawatts of electricity, amounting to an annual contribution of 1.5 petajoules. Of this 50 megawatts, an average of about 30 megawatts would be generated using a back pressure turbine and the remaining 20 megawatts would be generated through a condensing turbine. The steam required for the condensing turbine would constitute an additional heat requirement which would be met by the consumption of an additional 3.3 petajoules of hog fuel. It has been assumed that one North Coast kraft mill with no existing electricity generating capacity will install turbogenerator facilities which will produce an average of 20 megawatts. In addition, new kraft capacity brought on line in the Interior is assumed to produce the equivalent of 25 average megawatts for a 900 tonne per day operation. By the year 2000, cogeneration is expected to supply approximately 12.0 petajoules of electricity.

The consumption of natural gas and heavy fuel oil is determined residually to meet the total energy requirements of the mill. For the three mill groups with access to natural gas, it is assumed that the relationship between natural gas and heavy fuel oil consumption will follow historical patterns. The forecast assumes that natural gas service will be introduced to Vancouver Island in 1986 and that four mills will consequently have access to natural gas.[9] As indicated in Chapter 10 a substantial excess supply of heavy fuel oil is unlikely to materialize and should not significantly impede the penetration of natural gas in the Vancouver Island pulp and paper market. Tables 5.1.4 through 5.1.10 present a forecast of energy requirements for each of the five regions referred to in Table 5.1.1, for the Province and Vancouver Island in aggregate.

---

[9] A southern route for the Vanouver Island gas pipeline has been assumed in this forecast. This route would provide natural gas service to the mills at Crofton, Elk Falls, Harmac and Port Alberni. If a northern route is selected, the pulp mill at Powell River would also have access to natural gas.

TABLE 5.1.4

FORECAST OF PULP AND PAPER ENERGY REQUIREMENTS; NEWSPRINT MILLS

(PETAJOULES)

YEAR	NATURAL GAS	HEAVY FUEL OIL	L,P,G,	DIESEL FUEL OIL	HOG FUEL	PULPING LIQUORS	ELECT,	SELF-GEN ELECTRICITY	TOTAL REQTS
1978	.00	16.28	.06	.13	12.66	29.02	8.74	1.85	68.74
1979	.00	15.78	.06	.15	14.49	27.67	9.29	1.43	68.87
1980	.00	14.14	.07	.21	17.39	30.39	9.47	1.74	73.40
1981	.00	13.04	.07	.14	16.76	23.73	8.23	1.79	63.77
1982	.00	14.08	.06	.14	15.03	23.70	8.85	1.66	63.52
1983	.00	12.82	.06	.12	17.11	25.15	10.10	1.66	67.02
1984	.00	13.19	.06	.13	17.38	25.74	10.45	1.66	68.59
1985	.00	13.32	.06	.13	17.32	25.65	10.25	1.66	68.39
1986	6.64	6.57	.06	.13	16.82	24.80	9.70	1.66	66.38
1987	6.80	6.73	.06	.13	16.93	24.96	9.61	1.66	66.89
1988	7.11	7.04	.06	.14	17.44	25.71	9.79	1.66	68.94
1989	7.33	7.26	.06	.14	17.79	26.23	9.86	1.66	70.33
1990	7.55	7.47	.06	.15	18.15	26.75	9.93	1.66	71.72
1991	7.91	7.73	.07	.15	18.10	27.26	10.06	1.66	72.93
1992	8.21	8.03	.07	.16	18.64	28.07	10.25	1.66	75.09
1993	7.89	7.71	.07	.15	19.18	24.70	11.40	1.66	72.75
1994	8.17	7.99	.07	.16	19.59	24.91	11.74	1.66	74.29
1995	8.47	8.29	.07	.16	20.01	25.13	12.09	1.66	75.88
1996	9.46	7.39	.07	.16	20.56	25.25	12.27	1.66	76.82
1997	9.69	7.57	.07	.17	20.64	25.36	12.45	1.66	77.61
1998	9.97	7.79	.08	.17	20.59	25.48	12.64	1.66	78.37
1999	10.20	7.97	.08	.18	20.43	25.55	12.77	1.66	78.83
2000	10.20	7.97	.08	.18	20.40	25.55	12.76	1.66	78.79
ANNUAL GROWTH RATES									
1981-1990	.00	¯6.00	¯1.15	.23	.89	1.34	2.11	¯.85	1.31
1990-2000	3.05	.64	1.87	1.89	1.18	¯.46	2.54	.00	.94
1981-2000	.00	¯2.56	.43	1.10	1.04	.39	2.33	¯.41	1.12

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

TABLE 5.1.5

FORECAST OF PULP AND PAPER ENERGY REQUIREMENTS; S, COAST KRAFT MILLS

(PETAJOULES)

YEAR	NATURAL GAS	HEAVY FUEL OIL	L,P,G,	DIESEL FUEL OIL	HOG FUEL	PULPING LIQUORS	ELECT,	SELF-GEN ELECTRICITY	TOTAL REQTS
1978	.00	9.56	.05	.04	11.44	30.94	1.66	.10	53.80
1979	.00	10.33	.06	.05	12.24	30.68	1.60	.11	55.08
1980	.00	9.84	.08	.06	10.01	33.02	1.75	.10	54.87
1981	.00	9.09	.06	.06	7.94	27.40	1.57	.10	46.21
1982	.00	7.62	.06	.05	8.34	23.26	1.47	.09	40.88
1983	.00	7.65	.06	.05	10.27	25.28	1.01	.09	44.41
1984	.00	8.33	.07	.05	9.48	25.95	1.26	.09	45.21
1985	.00	7.82	.06	.05	10.27	25.86	1.27	.09	45.42
1986	1.39	6.32	.06	.05	9.96	25.00	1.24	.09	44.10
1987	1.44	6.56	.06	.05	9.60	25.16	1.34	.09	44.31
1988	1.49	6.76	.07	.05	10.03	25.92	1.32	.09	45.72
1989	1.37	6.24	.06	.05	10.37	26.44	1.34	.09	45.96
1990	1.39	6.31	.06	.05	10.62	26.97	1.38	.09	46.85
1991	1.39	6.32	.06	.05	10.98	27.50	1.40	.09	47.79
1992	1.41	6.41	.06	.05	11.46	28.33	1.44	.09	49.24
1993	1.45	6.59	.06	.05	11.80	29.18	1.48	.09	50.71
1994	1.49	6.78	.07	.05	12.16	30.06	1.52	.09	52.21
1995	1.61	7.32	.07	.05	12.52	30.96	1.26	.09	53.88
1996	1.63	7.44	.07	.06	12.71	31.43	1.27	.09	54.69
1997	1.67	7.59	.07	.06	12.81	31.89	1.29	.09	55.47
1998	1.71	7.79	.08	.06	12.83	32.37	1.31	.09	56.23
1999	1.75	7.94	.08	.06	12.76	32.70	1.32	.09	56.69
2000	1.74	7.92	.08	.06	12.75	32.70	1.32	.09	56.64
ANNUAL GROWTH RATES									
1981-1990	.00	-3.98	1.16	-2.16	3.29	-.18	-1.44	-1.54	.15
1990-2000	2.30	2.30	2.36	2.35	1.84	1.95	-.48	.00	1.91
1981-2000	.00	-.72	1.79	.18	2.52	.93	-.93	-.73	1.08

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,

JUNE 1984

TABLE 5.1.6

FORECAST OF PULP AND PAPER ENERGY REQUIREMENTS; LOWER MAINLAND PAPER MILLS

(PETAJOULES)

YEAR	NATURAL GAS	HEAVY FUEL OIL	L.P.G.	DIESEL FUEL OIL	HOG FUEL	ELECT.	SELF-GEN ELECTRICITY	TOTAL REQTS
1978	2.22	.12	.01	.04	1.30	.93	.00	4.62
1979	2.25	.18	.01	.05	1.28	.98	.00	4.75
1980	2.20	.14	.01	.04	.88	.99	.00	4.26
1981	2.34	.19	.01	.04	1.14	.92	.00	4.64
1982	2.15	.01	.01	.01	1.30	.76	.00	4.24
1983	2.37	.02	.01	.01	1.18	.80	.00	4.38
1984	3.09	.02	.01	.01	1.38	1.02	.00	5.54
1985	3.11	.02	.01	.01	1.40	1.03	.00	5.58
1986	3.09	.02	.01	.01	1.40	1.03	.00	5.56
1987	3.07	.02	.01	.01	1.40	1.02	.00	5.53
1988	3.03	.02	.01	.01	1.40	1.02	.00	5.49
1989	2.99	.02	.01	.01	1.40	1.01	.00	5.45
1990	2.95	.02	.01	.01	1.40	1.01	.00	5.40
1991	2.91	.02	.01	.01	1.40	1.00	.00	5.35
1992	2.88	.02	.01	.01	1.40	1.00	.00	5.32
1993	2.86	.02	.01	.01	1.40	.99	.00	5.29
1994	2.85	.02	.01	.01	1.40	.99	.00	5.28
1995	2.84	.02	.01	.01	1.40	.99	.00	5.27
1996	2.83	.02	.01	.01	1.40	.98	.00	5.26
1997	2.83	.02	.01	.01	1.37	.98	.00	5.25
1998	2.84	.02	.01	.01	1.37	.98	.00	5.23
1999	2.85	.02	.01	.01	1.35	.98	.00	5.22
2000	2.84	.02	.01	.01	1.35	.98	.00	5.20
				ANNUAL GROWTH RATES				
1981-1990	2.59	¯22.90	4.17	¯15.18	2.29	1.02	.00	1.68
1990-2000	¯.38	.00	.00	.00	¯.37	¯.32	.00	¯.36
1981-2000	1.02	¯11.59	1.95	¯7.50	.88	.31	.00	.60

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,

JUNE 1984

TABLE 5.1.7

FORECAST OF PULP AND PAPER ENERGY REQUIREMENTS; INTERIOR KRAFT MILLS

(PETAJOULES)

YEAR	NATURAL GAS	HEAVY FUEL OIL	L.P.G.	DIESEL FUEL OIL	HOG FUEL	PULPING LIQUORS	ELECT.	SELF-GEN ELECTRICITY	TOTAL REQTS
1978	15.59	1.81	.02	.17	16.16	46.47	3.76	.00	83.99
1979	15.85	2.36	.02	.21	14.94	45.45	3.82	.00	82.64
1980	18.14	.98	.01	.22	15.49	49.37	3.56	.00	87.78
1981	15.12	.65	.02	.32	13.87	41.98	3.11	.00	75.07
1982	16.90	.84	.03	.17	17.08	48.14	4.31	.00	87.48
1983	13.03	.64	.02	.13	17.66	46.70	5.27	.00	83.46
1984	12.69	.62	.02	.13	17.53	46.35	5.22	.00	82.57
1985	12.45	.61	.02	.13	17.42	46.05	5.18	.00	81.86
1986	11.85	.58	.02	.12	16.68	44.11	5.01	.00	78.37
1987	11.87	.58	.02	.12	16.82	44.47	5.03	.00	78.91
1988	12.20	.60	.02	.12	17.47	46.19	5.15	.00	81.75
1989	11.20	.55	.02	.11	22.13	47.36	4.57	.00	85.94
1990	11.42	.56	.02	.12	22.65	48.57	4.64	.00	87.98
1991	12.18	.60	.02	.12	24.83	49.79	4.04	.00	91.53
1992	12.00	.59	.02	.12	23.64	47.04	5.17	.00	88.57
1993	12.76	.63	.02	.13	25.07	50.34	5.37	.00	94.32
1994	12.79	.63	.02	.13	24.15	48.22	6.47	.00	92.42
1995	13.46	.67	.03	.14	25.47	51.27	6.68	.00	97.71
1996	13.78	.69	.03	.14	26.17	52.88	6.78	.00	100.46
1997	14.10	.71	.03	.15	26.86	54.48	6.88	.00	103.20
1998	14.42	.73	.03	.15	27.57	56.12	6.99	.00	106.01
1999	14.62	.74	.03	.15	28.05	57.23	7.06	.00	107.88
2000	14.57	.74	.03	.15	28.05	57.23	7.05	.00	107.82
					ANNUAL GROWTH RATES				
1981-1990	¯3.07	¯1.65	3.07	¯10.62	5.60	1.63	4.55	.00	1.78
1990-2000	2.46	2.82	2.92	2.83	2.16	1.65	4.27	.00	2.05
1981-2000	¯.20	.68	2.99	¯3.78	3.78	1.64	4.40	.00	1.92

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

TABLE 5.1.8

FORECAST OF PULP AND PAPER ENERGY REQUIREMENTS; N, COAST KRAFT MILLS

(PETAJOULES)

YEAR	NATURAL GAS	HEAVY FUEL OIL	L,P,G,	DIESEL FUEL OIL	HOG FUEL	PULPING LIQUORS	ELECT,	SELF-GEN ELECTRICITY	TOTAL REQTS
1978	3.66	.75	.01	.09	1.32	16.56	1.58	.00	23.99
1979	7.06	1.40	.01	.22	1.07	14.31	1.43	.00	25.50
1980	8.09	.69	.01	.19	1.09	16.29	1.53	.00	27.89
1981	7.98	.74	.01	.15	.78	14.04	1.38	.00	25.07
1982	6.78	.50	.02	.12	1.24	14.37	1.41	.00	24.44
1983	6.85	.51	.02	.13	1.82	15.62	1.52	.00	26.46
1984	6.70	.50	.02	.12	2.27	16.03	1.55	.00	27.19
1985	6.37	.47	.02	.12	2.66	15.98	1.54	.00	27.16
1986	5.89	.44	.01	.11	2.96	15.45	1.49	.00	26.34
1987	5.65	.42	.01	.10	3.37	15.55	1.49	.00	26.58
1988	5.51	.41	.01	.10	3.87	16.02	1.53	.00	27.44
1989	5.30	.39	.01	.10	4.35	16.34	1.55	.00	28.05
1990	5.75	.43	.01	.10	4.85	16.66	1.05	.00	28.86
1991	5.83	.43	.01	.11	4.95	17.00	1.07	.00	29.40
1992	5.99	.44	.01	.11	5.10	17.50	1.09	.00	30.25
1993	6.16	.46	.01	.11	5.25	18.03	1.12	.00	31.15
1994	6.34	.47	.02	.12	5.41	18.57	1.15	.00	32.07
1995	6.33	.47	.02	.12	5.42	18.60	1.15	.00	32.10
1996	6.32	.47	.02	.12	5.42	18.60	1.14	.00	32.09
1997	6.31	.47	.02	.12	5.42	18.60	1.14	.00	32.07
1998	6.30	.47	.02	.12	5.42	18.60	1.14	.00	32.05
1999	6.28	.46	.02	.12	5.42	18.60	1.14	.00	32.03
2000	6.27	.46	.02	.11	5.42	18.60	1.13	.00	32.01
					ANNUAL GROWTH RATES				
1981-1990	¯3.57	¯5.89	.00	¯3.89	22.56	1.92	¯2.95	.00	1.58
1990-2000	.87	.86	.69	.83	1.11	1.11	.74	.00	1.04
1981-2000	¯1.26	¯2.40	.36	¯1.43	10.75	1.49	¯1.03	.00	1.29

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,

JUNE 1984

TABLE 5.1.9

FORECAST OF PULP AND PAPER ENERGY REQUIREMENTS; PROVINCE

(PETAJOULES)

YEAR	NATURAL GAS	COAL AND COKE	HEAVY FUEL OIL	L.P.G.	DIESEL FUEL OIL	HOG FUEL	PULPING LIQUORS	ELECT.	SELF-GEN ELECTRICITY	TOTAL REQTS
1978	21.47	.00	30.50	.15	.48	43.02	123.00	16.67	2.25	237.55
1979	25.16	.00	32.15	.15	.69	44.14	118.11	17.13	1.89	239.43
1980	28.43	.00	25.80	.19	.72	44.86	129.07	17.31	1.84	248.21
1981	25.44	.00	23.70	.17	.71	40.49	107.16	15.21	1.89	214.76
1982	25.83	.00	23.05	.18	.49	42.99	109.47	16.80	1.74	220.56
1983	22.25	.00	21.63	.17	.44	48.05	112.75	18.71	1.74	225.73
1984	22.48	.00	22.65	.18	.44	48.04	114.06	19.51	1.74	229.11
1985	21.93	.00	22.25	.17	.43	49.08	113.53	19.28	1.74	228.41
1986	28.86	.00	13.93	.17	.41	47.83	109.36	18.46	1.74	220.75
1987	28.82	.00	14.31	.17	.41	48.12	110.15	18.49	1.74	222.22
1988	29.34	.00	14.82	.18	.42	50.20	113.84	18.81	1.74	229.36
1989	28.20	.00	14.46	.17	.41	56.05	116.37	18.34	1.74	235.73
1990	29.05	.00	14.78	.17	.42	57.67	118.96	18.02	1.74	240.81
1991	30.21	.00	15.10	.18	.44	60.26	121.55	17.57	1.74	247.05
1992	30.48	.00	15.49	.18	.45	60.24	120.95	18.95	1.74	248.48
1993	31.11	.00	15.41	.18	.45	62.70	122.25	20.36	1.74	254.22
1994	31.64	.00	15.89	.19	.46	62.71	121.77	21.87	1.74	256.26
1995	32.71	.00	16.77	.20	.48	64.83	125.96	22.16	1.74	264.84
1996	34.04	.00	16.00	.20	.49	66.26	128.15	22.45	1.74	269.32
1997	34.60	.00	16.35	.20	.49	67.12	130.33	22.75	1.74	273.60
1998	35.24	.00	16.79	.21	.50	67.78	132.57	23.06	1.74	277.89
1999	35.70	.00	17.14	.21	.51	68.01	134.09	23.26	1.74	280.65
2000	35.61	.00	17.10	.21	.51	67.96	134.09	23.24	1.74	280.46
ANNUAL GROWTH RATES										
1981-1990	1.49	.00	¯5.11	.46	¯5.59	4.01	1.17	1.90	¯.89	1.28
1990-2000	2.06	.00	1.47	1.96	1.91	1.66	1.20	2.58	.00	1.54
1981-2000	1.79	.00	¯1.70	1.25	¯1.71	2.76	1.19	2.25	¯.42	1.41

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,

JUNE 1984

TABLE 5.1.10

FORECAST OF PULP AND PAPER ENERGY REQUIREMENTS; VANCOUVER ISLAND-SOUTHERN ROUTE

(INCLUDES PORT MELLON ,WOODFIBRE AND POWELL RIVER)

(PETAJOULES)

YEAR	NATURAL GAS	HEAVY FUEL OIL	L,P,G,	DIESEL FUEL OIL	HOG FUEL	PULPING LIQUORS	ELECT,	SELF-GEN ELECTRICITY	TOTAL REQTS
1978	.00	25.84	.11	.17	24.10	59.96	10.40	1.95	122.54
1979	.00	26.11	.12	.20	26.72	58.36	10.90	1.55	123.95
1980	.00	23.98	.15	.27	27.40	63.41	11.22	1.84	128.27
1981	.00	22.13	.13	.20	24.69	51.13	9.80	1.89	109.98
1982	.00	21.70	.12	.18	23.37	46.95	10.32	1.74	104.39
1983	.00	20.47	.12	.17	27.38	50.43	11.12	1.74	111.43
1984	.00	21.51	.12	.18	26.86	51.68	11.71	1.74	113.81
1985	.00	21.14	.12	.18	27.60	51.51	11.52	1.74	113.81
1986	8.03	12.89	.12	.17	26.79	49.80	10.94	1.74	110.48
1987	8.25	13.30	.12	.18	26.53	50.13	10.95	1.74	111.20
1988	8.60	13.80	.13	.19	27.47	51.63	11.11	1.74	114.66
1989	8.71	13.50	.12	.19	28.16	52.66	11.21	1.74	116.29
1990	8.94	13.78	.13	.19	28.77	53.72	11.31	1.74	118.57
1991	9.29	14.05	.13	.20	29.08	54.76	11.47	1.74	120.72
1992	9.62	14.44	.13	.21	30.10	56.40	11.69	1.74	124.34
1993	9.33	14.31	.13	.20	30.98	53.88	12.88	1.74	123.46
1994	9.66	14.78	.14	.21	31.75	54.97	13.26	1.74	126.50
1995	10.08	15.61	.14	.22	32.54	56.09	13.35	1.74	129.76
1996	11.10	14.83	.14	.22	33.27	56.67	13.55	1.74	131.52
1997	11.35	15.16	.15	.22	33.45	57.25	13.74	1.74	133.08
1998	11.68	15.57	.15	.23	33.42	57.85	13.95	1.74	134.60
1999	11.95	15.92	.15	.23	33.19	58.25	14.09	1.74	135.52
2000	11.94	15.88	.15	.23	33.14	58.25	14.07	1.74	135.43
ANNUAL GROWTH RATES									
1981-1990	.00	-5.13	-.09	-.40	1.71	.55	1.60	-.89	.84
1990-2000	2.94	1.43	2.11	2.00	1.43	.81	2.21	.00	1.34
1981-2000	.00	-1.73	1.06	.86	1.56	.69	1.92	-.42	1.10

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,

JUNE 1984

The growth rates calculated from 1981 to 1990 and to the year 2000 are biased by the fact that 1981 was a strike year. For the province in total, natural gas is forecast to increase from 28.4 petajoules in 1980 to 35.6 petajoules in 2000, at 1.1 percent a year, principally as a result of the Vancouver Island pipeline. Heavy fuel oil correspondingly declines from 25.8 petajoules in 1980 to 17.1 petajoules in 2000. Hog fuel consumption is forecast to increase at a rate of 2.1 percent from 44.9 petajoules in 1980 to 68 petajoules in 2000. Purchased electricity requirements increase from 17.3 petajoules in 1980 to 23.2 petajoules in 2000, at an average annual rate of 1.5 percent. The increase in electricity requirements occurs as the impact of increased newsprint production, substitution of TMP for stoneground wood and kraft pulp, and CTMP mills more than offset the impact of increased cogeneration.

Table 5.1.10 indicates that Vancouver Island natural gas requirements are expected to reach 11.9 PJ by the year 2000. This compares with the estimate of 5.9 PJ presented in the Natural Gas Supply to Vancouver Island Technical Report. The higher estimate presented here primarily reflects a deficit of domestic heavy fuel oil whereas the Technical Report forecast surpluses. More detail on heavy fuel oil supply and the supply/demand balance is presented in Chapters 9 and 10.

5.1.2 Wood Products Industry

5.1.2.1 Introduction

The wood products industry in British Columbia is composed of a large number of establishments which produce sawn lumber, plywood, veneer, shingles, shakes, and particle board. For the purpose of this forecast, the Ministry has divided the wood products industry into three regions: South Coast, North Coast and Interior.

The Coastal industry produces sawn lumber and wood products which are destined principally for the overseas export market while the Interior mills produce products principally for the U.S. market.

5.1.2.2 Historical Profile

Table 5.1.11 presents a historical production profile for the major wood products. Since the early 1960's there has been a significant shift in the industry from the Coast to the Interior. Between 1973 and 1982 for example, the contribution to total sawn lumber by Interior mills has increased from 58 to 71 percent. The lumber industry declined markedly in the 1981/82 period as the effects of the 1981 strike and prolonged economic downturn were felt. Coastal producers were affected more than their counterparts in the Interior.

An historical profile of the consumption of purchased fuels, as reported by Statistics Canada, for the wood products industry is presented in Table 5.1.12. Noteworthy has been the significant increase in natural gas demand that resulted from the expansion of the Interior industry where major volumes of natural gas are consumed for kiln drying lumber destined for the U.S. construction industry. Not only has the size of the Interior industry increased, the proportion of lumber which is kiln dried has increased over time as well.

Hog fuel is not included in the purchased fuel estimates presented in Table 5.1.12 but Ministry estimates indicate that approximately 28.4 PJ were consumed by the wood products industry in 1979.

Table 5.1.11

Wood Products Industry Historical Production

	Lumber Production[1] (million board feet)			Plywood Shipments[2]	Shingle/Shake Shipments[2]
	Coast	Interior	Total	(million sq.ft.)[3]	(thousand squares)
1973	4403	6038	10441	2203	2556
1974	3405	5378	8783	1768	2036
1975	2504	4965	7469	1744	1968
1976	3988	6757	10745	2144	2624
1977	4499	7539	12038	2343	2906
1978	4803	7742	12545	2548	3492
1979	4657	7861	12518	2307	3400
1980	4252	7727	11980	2230	3266
1981	3458	6966	10424	1953	3105
1982	3002	6943	9745	1654	2920

[1] Statistics Canada

[2] Statistics Canada, Council of Forest Industries

[3] 3/8 inch basis

Electricity has maintained a relatively constant share of total energy requirements while the shares of all refined petroleum products have declined over time.

TABLE 5.1.12

WOOD PRODUCTS INDUSTRY ENERGY REQUIREMENTS

(PETAJOULES)

YEAR	NATURAL GAS	COAL AND COKE	HEAVY FUEL OIL	LIGHT FUEL OIL	L.P.G.	DIESEL FUEL OIL	ELECT.	TOTAL REQTS
1971	4.709	.000	.546	.212	.779	1.716	3.928	11.890
1972	6.217	.000	.686	.266	.957	2.156	4.482	14.763
1973	7.445	.000	.652	.253	.950	2.049	5.278	16.627
1974	7.204	.000	.516	.241	1.069	2.132	5.076	16.239
1975	6.324	.000	.350	.153	.586	1.585	5.054	14.052
1976	8.891	.000	.391	.196	.826	1.932	5.934	18.170
1977	10.471	.000	.369	.121	.987	1.944	6.724	20.616
1978	11.766	.000	.200	.124	1.099	2.002	7.132	22.323
1979	11.133	.000	.193	.143	1.070	2.327	7.412	22.278
1980	10.556	.000	.179	.235	.941	2.378	7.419	21.708
				ANNUAL GROWTH RATES				
1971-1980	9.38	.00	¯11.63	1.14	2.13	3.69	7.32	6.92

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

5.1.2.3 Forecast Period Assumptions

Industry Production

The production of all wood products is forecast to grow at the rate of increase in GDP in the wood sector, as presented in Chapter 2, but constrained within the context of total fibre availability and production activity within the pulp and paper industry.

Table 5.1.13 presents the forecast of production along with the historical activity. The wood products industry reaches the binding constraint of the available forest resources in 1992. After 1992, increases in production would have to be met through the harvesting of wood not included within the annual allowable cut or through increased wood recovery efficiency. It should be noted that the latter increase in productivity would also reduce the volume of wood chips produced by the wood products industry and correspondingly reduce the production of kraft pulp.

5.1.2.4 Total Energy and Fuel Requirements Forecast

The energy requirements of the wood products industry were forecast using the methodology outlined in the Ministry's Staff Paper.[10]

---

[10] "The B.C. Energy Demand Forecasting and Planning Model," Staff Paper, March 1983.

TABLE 5.1.13

FORECAST OF LUMBER PRODUCTION

YEAR	LUMBER PRODUCTION (BILLION BOARD FEET) COAST	INTERIOR	TOTAL	PLYWOOD SHIPMENTS (B SQ FT)	SHINGLE/ SHAKE SHIPMENTS (MM SQUARES)
1978	4.803	7.742	12.545	2.548	3.492
1979	4.650	7.861	12.511	2.307	3.400
1980	4.252	7.727	11.979	2.230	3.266
1981	3.458	6.966	10.424	1.953	3.105
1982	3.002	6.943	9.945	1.654	2.920
1983	3.877	7.331	11.207	1.864	3.291
1984	4.187	7.469	11.655	1.938	3.422
1985	4.549	7.456	12.005	1.997	3.525
1986	4.267	7.137	11.404	1.897	3.349
1987	4.375	7.258	11.633	1.935	3.416
1988	4.644	7.454	12.098	2.012	3.552
1989	4.646	7.452	12.098	2.012	3.552
1990	4.647	7.451	12.098	2.012	3.552
1991	4.903	7.437	12.340	2.052	3.623
1992	5.231	7.427	12.658	2.105	3.717
1993	5.354	7.416	12.770	2.124	3.749
1994	5.334	7.421	12.755	2.121	3.745
1995	5.323	7.416	12.739	2.119	3.740
1996	5.317	7.413	12.730	2.117	3.738
1997	5.311	7.411	12.722	2.116	3.735
1998	5.305	7.408	12.713	2.114	3.733
1999	5.301	7.407	12.708	2.114	3.731
2000	5.301	7.407	12.708	2.114	3.731
			ANNUAL GROWTH RATES		
1981-1990	3.34	.75	1.67	.33	1.51
1990-2000	1.33	-.06	.49	.49	.49
1981-2000	2.27	.32	1.05	.42	.97

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,

JUNE 1984

In summary, shares of individual fuels are determined by the relative price of each fuel. The prices of individual fuels are weighted by their associated market shares and summed to produce an average energy price for the industry. The wood production forecast, along with the average energy price, is used to obtain the forecast of total energy requirements. The market shares are then multiplied by total energy requirements to produce estimates of individual fuel consumption.

As mentioned above, historical energy consumption data excludes the impact of the utilization of hog fuel. Part of the reduction in fuel requirements previously ascribed to price induced conservation has been in fact a substitution of hog fuel for purchased fuels. This effect was incorporated by modifying the methodology so that the consumption of hog fuel per unit of output, observed in 1979, was held constant throughout the forecast period. Also it was assumed that the observed reduction in energy requirements relative to the consumption which would have prevailed in the presence of 1979 real prices was attributable to a substitution of hog fuel for purchased fuels. Estimates of regional hog fuel consumption are prepared for the determination of regional hog fuel supply/demand balances and are presented in Chapter 10.

A forecast of energy requirements for the wood products industry is summarized in Table 5.1.14. The decreased level of production for 1981 and 1982 that was presented in Table 5.1.13 is reflected in the energy requirements, with a more or less complete recovery by the end of the 1980's. Total energy requirements are forecast to increase from 42.2 petajoules in 1981 to 54.1 petajoules in 2000, at an average annual growth rate of 1.3 percent. It is important to note that there is virtually no growth in total requirements beyond 1992 as the full effect of the limited forest resources is felt.

TABLE 5.1.14

FORECAST OF WOOD PRODUCTS INDUSTRY ENERGY REQUIREMENTS

(IN PETAJOULES)

YEAR	NATURAL GAS	COAL AND COKE	HEAVY FUEL OIL	LIGHT FUEL OIL	L.P.G.	DIESEL FUEL OIL	HOG FUEL	ELECT.	TOTAL REQTS
1978	11.767	.000	.200	.124	1.099	2.002	29.289	7.133	51.614
1979	11.134	.000	.193	.143	1.070	2.327	28.350	7.413	50.630
1980	10.555	.000	.179	.235	.942	2.379	28.350	7.418	50.058
1981	8.758	.000	.089	.189	.637	2.027	23.817	6.724	42.241
1982	8.330	.000	.083	.175	.592	1.883	22.121	6.081	39.265
1983	9.011	.000	.089	.188	.635	2.014	29.608	6.422	47.967
1984	9.224	.000	.089	.190	.641	2.056	29.962	6.542	48.704
1985	8.990	.000	.089	.189	.638	2.038	32.347	6.605	50.896
1986	9.354	.000	.034	.072	.245	1.961	29.733	6.207	47.606
1987	9.325	.000	.034	.073	.246	1.962	31.743	6.242	49.625
1988	9.274	.000	.034	.073	.246	1.975	33.570	6.378	51.550
1989	8.940	.000	.034	.071	.240	1.924	34.268	6.292	51.769
1990	8.666	.000	.033	.070	.235	1.880	34.807	6.209	51.900
1991	8.488	.000	.033	.069	.233	1.860	35.416	6.217	52.316
1992	8.367	.000	.032	.069	.231	1.853	36.795	6.253	53.600
1993	8.278	.000	.031	.066	.225	1.862	37.498	6.210	54.170
1994	8.219	.000	.032	.068	.229	1.852	37.577	6.177	54.154
1995	8.226	.000	.032	.067	.226	1.845	37.235	6.128	53.759
1996	8.161	.000	.032	.067	.227	1.835	37.673	6.104	54.099
1997	8.103	.000	.032	.067	.226	1.823	37.782	6.071	54.104
1998	8.081	.000	.031	.066	.222	1.814	37.504	6.026	53.744
1999	7.991	.000	.031	.066	.223	1.800	37.990	6.005	54.106
2000	7.942	.000	.031	.066	.222	1.790	38.123	5.975	54.149
					ANNUAL GROWTH RATES				
1981-1990	¯.12	.00	¯10.44	¯10.45	¯10.49	¯.83	4.31	¯.88	2.31
1990-2000	¯.87	.00	¯.62	¯.59	¯.57	¯.49	.91	¯.38	.43
1981-2000	¯.51	.00	¯5.40	¯5.39	¯5.40	¯.65	2.51	¯.62	1.32

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

The most significant development with regard to the industry's energy consumption patterns is the substitution of hog fuel for purchased fuels. Hog fuel increases its share of total energy requirements to 70 percent by the year 2000 from 56 percent in 1981 as major price increases for natural gas and electricity result in lower requirements for these fuels. As well, the wood products industry is assumed to have first call upon hog fuel supplies before it is made available to the pulp and paper mills.

Natural gas consumption declines at an annual rate of 0.5 percent between 1981 and 2000, while the Interior lumber production increases at a rate of 0.3 percent over the same time period. The Vancouver Island gas pipeline provides only a modest contribution to natural gas consumption because there is limited oil consumption which has potential for displacement.

Electricity requirements are essentially the same in 1981 and 2000, although total lumber production has increased at a rate of about 1.1 percent per year. The industry is forecast to reduce its electricity consumption on a per unit basis in response to the real increases assumed for electricity rates.

5.2 Primary Metals Industry

5.2.1 Introduction

The primary metals industry in British Columbia consists of two large metal smelting operations and a number of smaller producers. The industry produces aluminum, lead, zinc, silver, steel, copper and other metal products. The Aluminum Company of Canada (Alcan) produces aluminum ingots from its major smelter at Kitimat. The Consolidated Mining and Smelting Company (Cominco) operates its Sullivan lead/zinc mine at Kimberley and a large lead/zinc smelting complex at Trail. A large proportion of this production is destined directly for the export market with the major markets being the United States and Japan. This industry is the largest industrial consumer of electricity in the province and relies on the supply being generated mainly from own hydroelectric sources.

5.2.2 Historical Profile

Table 5.2.1 presents the historical energy consumption data for the industry for the years 1971 through 1980. Both Alcan and Cominco generate significant amounts of hydroelectricity from company owned generation facilities.

Alcan developed the Nechako Reservoir and the Kemano power house which is name plate rated at 896 megawatts (MW). Most of the energy from this development is used at its Kitimat Smelter. From 1980 through 1983, Alcan had an agreement with B.C. Hydro to provide annually up to 1200 gigawatt-hours (GWH) of electricity (4.3 petajoules) on an as needed basis.

TABLE 5.2.1

PRIMARY METALS INDUSTRY
HISTORICAL ENERGY REQUIREMENTS

(PETAJOULES)

YEAR	NATURAL GAS	COAL AND COKE	HEAVY FUEL OIL	LIGHT FUEL OIL	L.P.G.	DIESEL FUEL OIL	ELECT.	SELF-GEN ELECTRICITY	TOTAL REQTS
1971	2.270	.000	.000	.452	.031	.074	.810	24.080	27.717
1972	2.382	.000	.000	.389	.009	.063	.731	24.207	27.781
1973	2.372	.000	.000	.259	.006	.042	.425	25.673	28.777
1974	3.783	.000	.000	.176	.007	.060	.508	23.711	28.245
1975	5.145	.000	.002	.240	.008	.077	.465	20.524	26.461
1976	5.201	.000	.018	.180	.004	.097	.460	21.780	27.739
1977	5.523	.000	.038	.193	.007	.063	.535	24.601	30.959
1978	5.671	.000	.031	.267	.008	.094	.680	24.447	31.200
1979	6.272	.000	.187	.089	.011	.106	.643	24.456	31.763
1980	4.744	.000	.124	.102	.011	.108	.000	24.490	29.579
ANNUAL GROWTH RATES									
1971-1980	8.53	.00	.00	¯15.22	¯10.89	4.35	.00	.19	.73

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

Cominco and its 100 percent owned subsidiary West Kootenay Power and Light (WKPL) operate 6 dams which are entitled to produce about 4800-4900 gigawatt-hours under the Canal Plant agreement. WKPL produces approximately 1510 GWH and has a direct call upon 657 GWH from Cominco until 1990, leaving Cominco approximately 2700 GWH until 1990 and approximately 3300 GWH thereafter.

Cominco also consumes a major volume of natural gas in both its smelter and chemical operations. In the former, gas is used in the blast furnaces while in the chemical operations it is used principally as a feedstock in the production of ammonia which in turn is used in the production of urea formaldehyde. This chemical is employed in the production of fertilizers which provide an outlet for recovered sulphur from Cominco's smelting process. As well, Cominco uses some coal as a reagent in the smelting process. The remaining companies use relatively small volumes of all fuel types.

The natural gas feedstock requirements for Cominco's Trail operations are excluded from this chapter. These requirements are, however, reported later in Chapter 7.

5.2.3 Industry Production Forecast

There is considerable scope for growth in the primary metals industry in B.C.. During 1980/81 a large number of enquiries were made to B.C. Hydro regarding the purchase of electricity for new industrial complexes. However, following the advent of the economic recession in 1982, many of these proposals have been delayed indefinitely or cancelled. While these economic events may have delayed such projects it is likely that a few of them will advance as the recovery takes hold and the growth in demand for metal products requires the construction of additional productive capacity.

This forecast assumes that a ferro-silicon smelter complex with an annual output of 50,000 tonnes will be built by the early 1990's. This complex could be undertaken by the Cominco-Mitsui consortium and consume electricity from the Cominco electricity generation facilities, or be undertaken by one of two other proponents and receive power from B.C. Hydro. It is further assumed that a 100,000 tonne copper smelter will be built by the early 1990's with a location probably in the Highland Valley supplied by B.C. Hydro.

Cominco is also assumed to expand its zinc smelting facility in the mid 1990's, thereby creating additional load for electricity.

In January, 1984, the Aluminum Company of Canada (Alcan) applied to the Comptroller of Water Rights for approval of the design for the Kemano Completion hydroelectric project, and to the Minister of Energy, Mines and Petroleum Resources for an Energy Removal Certificate for an aluminum smelter at Vanderhoof and another smelter at an unspecified location over time. Vanderhoof smelter would have a capacity of 171,000 tonnes/year and it could be in full production by the early 1990's. The second smelter could have a capacity of about 200,000 tonnes/year; locations and in-service date are undecided. Alcan's proposed hydroelectric smelter development is under review and no decisions have been taken by the Province on its approval.

In this forecast, it is assumed that two new 180,000 tonne aluminum smelters, one in 1990 and another in 1999 will be built in B.C., (not necessarily by Alcan) and that each will require roughly 2700 GWh (9.7 PJ)/year. While this assumption is subject to considerable uncertainty, it is based on studies which identify B.C. as a potentially desirable location for new smelter capacity compared to other parts of the world, and it is based on the continuing interest of Alcan and other major aluminum producers in locating in B.C. Inclusion of an aluminum smelter in the forecast does not presuppose that any applications to build a new smelter would be approved by the government; such a decision would depend on the outcome of extensive review and possibly a public hearing.

5.2.4 Forecast of Energy and Fuels Consumption

The total energy requirements of the primary metals industry are forecast to increase from 28.5 petajoules in 1981 to 41.8 petajoules in 1990 and 55.4 petajoules in the year 2000, at an average annual growth rate of 4.3 percent from 1981 to 1990 and 2.9 percent during the 1990's. The major source of this growth is to be found in the consumption of both purchased and self-generated electricity. Total electricity consumption is forecast to increase from 25.2 petajoules in 1981 to 37.8 petajoules in 1990 and 50.5 petajoules by the year 2000. (Table 5.2.2).

Two of the new electricity intensive projects are forecast to consume a total of 2.0 petajoules of electricity annually by the year 2000. The ferro-silicon complex is assumed to require 470 GWH (1.7 petajoules), and the copper smelter to require 90 GWH (0.3 petajoules). This forecast of purchased electricity requirements is significantly lower than that contained in the

TABLE 5.2.2

PRIMARY METALS INDUSTRY
ENERGY REQUIREMENTS

(PETAJOULES)

YEAR	NATURAL GAS	HEAVY FUEL OIL	LIGHT FUEL OIL	DIESEL FUEL OIL	L.P.G.	ELECT.	SELF-GEN ELECTRICITY	TOTAL REQTS
1978	2.946	.024	.212	.075	.007	.680	24.447	28.391
1979	3.251	.147	.070	.083	.008	.643	24.456	28.658
1980	2.968	.118	.056	.067	.007	.644	24.490	28.350
1981	3.087	.109	.052	.062	.006	.644	24.552	28.512
1982	3.105	.097	.046	.055	.006	.644	24.459	28.412
1983	3.180	.125	.059	.071	.007	.644	25.105	29.191
1984	3.276	.145	.069	.082	.006	.644	25.283	29.507
1985	3.377	.157	.074	.088	.009	.644	25.468	29.817
1986	3.445	.135	.064	.076	.008	.644	25.468	29.840
1987	3.511	.139	.066	.078	.008	.644	27.045	31.491
1988	3.589	.141	.067	.080	.008	.644	27.045	31.574
1989	3.666	.143	.068	.081	.008	.644	27.045	31.655
1990	3.743	.145	.069	.082	.008	.986	36.765	41.798
1991	3.821	.146	.070	.083	.008	2.678	36.765	43.571
1992	3.900	.148	.070	.084	.009	2.678	36.765	43.654
1993	3.984	.150	.072	.085	.009	2.678	36.765	43.743
1994	4.070	.153	.073	.086	.009	2.678	36.765	43.834
1995	4.155	.155	.074	.088	.009	2.678	36.765	43.924
1996	4.241	.158	.075	.089	.009	2.678	36.765	44.015
1997	4.330	.160	.076	.090	.009	2.678	38.089	45.432
1998	4.416	.162	.077	.091	.009	2.678	38.089	45.522
1999	4.505	.164	.078	.093	.009	5.558	44.929	55.336
2000	4.591	.166	.079	.094	.010	5.558	44.929	55.427
ANNUAL GROWTH RATES								
1981-1990	2.16	3.22	3.19	3.16	3.25	4.85	4.59	4.34
1990-2000	2.06	1.36	1.36	1.38	2.26	18.88	2.03	2.86
1981-2000	2.11	2.24	2.23	2.21	2.73	12.01	3.23	3.56

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

Ministry's 1981 Forecast. The major deviation occurs in the assumption regarding the ferro-silicon complex and its associated electricity requirements. In the 1981 Forecast it was assumed that the requirements of the ferro-silicon plant would be much larger consuming about 1500 GWH (5.4 petajoules) and that the plant would be started up earlier.

The consumption of self-generated hydroelectricty is forecast to increase from 24.6 petajoules in 1981 to 36.8 petajoules in 1990 and 44.9 petajoules in the year 2000. The increased requirements in the late 1980's reflect the assumed "modernization" of the Cominco Trail operation and the construction of Alcan's first additional aluminum smelter. The modernization is expected to be in place by 1987 thereby increasing Cominco's electricity consumption by about 27 percent, while the Alcan smelter is projected to consume about 9.7 petajoules commencing in 1990. The second Alcan smelter is assumed to require an additional 9.7 petajoules of electricity and effectively exhausts the electricity generating capability of Alcan's Kemano and Kemano Completion projects.

Natural gas consumption is forecast to increase modestly from 3.0 petajoules in 1981 to 4.6 petajoules by the year 2000 at an average annual growth rate of 2.1 percent. The consumption of other fuel types is also forecast to increase modestly over time.

5.3 Chemicals

5.3.1 Introduction

The chemicals industry in British Columbia produces bleaching/ digesting agents for the pulp and paper industry, resins for the wood product industries, fertilizer and a range of miscellaneous chemical products for use in a variety of applications. The largest segment of demand for chemical products originates in the forest products industries and therefore, most of the energy requirements detailed in this section are derived based on production activity in pulp and paper, and wood product industries.

When forecasting electricity requirements, electricity consumption in the chemical industry is disaggregated into two components. One component identifies electricity consumption in the production of pulp and paper related chemicals and this demand is forecast to grow at the same rate as kraft pulp production. The second component specifies the use of electricity in the production of chemicals which are used in the non-pulp and paper subsector of the forest product industries. Growth of this component is related to growth in the contribution of the chemical industry to GDP.

Natural gas in the chemical industry is principally used in the production of resins for the wood products industries and therefore, this demand is forecast to grow at the same rate as GDP in the wood industry.

5.3.2 Historical Profile of the Industry

The purchased fuel data reported by Statistics Canada for this subsector reflect sharp discontinuities. Nevertheless, based on the last 10 to 12 years of data, this sector accounts for about 9 to 10 petajoules of purchased energy in British Columbia. In addition, Cominco uses about 2 petajoules of self-generated electricity at its Kimberley/Trail chemical fertilizer operations.

Currently, there are three major producers of resins products in the province. In addition, four major firms are engaged in the production of bleaching and digesting agents (chlorine, caustic soda and sodium chlorate). These firms rely principally on electricity and natural gas to meet their energy requirements. Most of the electricity consumption is attributable to the production of bleaching agents, while natural gas, oil products and waste gases are used in raising heat needed for the production of resins.

5.3.3 Forecast Period Assumptions

A detailed discussion on various assumptions which underly this forecast is provided earlier in Chapter 2 and section 5.1 of this chapter. Some of these assumptions, however, are briefly restated here.

The kraft production which determines a large portion of electricity demand in the chemicals industry is forecast to increase from 3.4 million tonnes in 1981 to 4.4 million tonnes by 2000 (Table 5.1.3). Currently, the kraft pulp production represents about 69 percent of the total pulp and paper production in B.C.. This share, however, is expected to decline to 61 percent by the end of the forecast period.

The total lumber production, on the otherhand, is expected to increase from 17,513 thousand cubic metres of solid wood equivalent (SWE) in 1981 to 21,358 thousand cubic metres by 2000.

Based on the economic assumptions outlined in Chapter 2, the chemicals industry component of the real gross provincial domestic product is forecast to increase at an annual rate of 1.4 percent over the 1981 to 2000 period.

No significant growth is forecast for Cominco's fertilizer/chemicals operations at Kimberley/Trail and consequently, the demand for self-generated electricity is assumed to stay at its 1982 level.*

5.3.4 Energy and Fuel Requirements

Table 5.3.1 presents the fuel specific energy requirements for the chemcial industry in British Columbia.

Total energy requirements for this subsector are forecast to increase from 10.6 petajoules in 1981 to 12.3 petajoules by 2000 indicating an annual average growth rate of 0.8 percent. The corresponding growth rates for electricity and natural gas are estimated as 1.2 percent and 1.1 percent respectively. Over the first half of the forecast period, however, the growth in natural gas requirements is expected to be higher. This higher growth rate estimated for natural gas reflects the displacement of heavy fuel oil in the chemical industry on Vancouver Island as a result of extension of natural gas service to the Island.

---

* Due to the difficulty of identifying electricity use for chemicals and fertilizer plants separately, the electricity requirements for Cominco's fertilizer production are also included here instead of in Section 5.6 which deals with petrochemicals.

TABLE 5.3.1

FORECAST OF CHEMICALS INDUSTRY ENERGY REQUIREMENTS

(PETAJOULES)

YEAR	NATURAL GAS	COAL AND COKE	HEAVY FUEL OIL	LIGHT FUEL OIL	L,P,G,	DIESEL FUEL OIL	ELECT,	SELF-GEN ELECTRICITY	TOTAL REQTS
1978	3.560	.000	.364	.088	.004	.015	5.271	1.987	11.289
1979	3.292	.000	.645	.167	.006	.047	5.656	1.482	11.295
1980	3.153	.000	.443	.062	.002	.043	5.822	2.050	11.575
1981	2.743	.000	.271	.038	.001	.027	5.343	2.176	10.599
1982	2.617	.000	.248	.035	.001	.024	5.050	2.113	10.088
1983	2.949	.000	.279	.039	.001	.027	5.180	2.113	10.596
1984	3.067	.000	.304	.042	.001	.030	5.352	2.113	10.909
1985	3.159	.000	.319	.044	.001	.031	5.405	2.113	11.072
1986	3.001	.000	.089	.045	.001	.032	5.261	2.113	10.542
1987	3.061	.000	.094	.048	.001	.034	5.306	2.113	10.657
1988	3.184	.000	.097	.050	.001	.035	5.469	2.113	10.949
1989	3.184	.000	.095	.049	.001	.034	5.601	2.113	11.077
1990	3.184	.000	.093	.047	.001	.033	5.730	2.113	11.201
1991	3.248	.000	.092	.047	.001	.033	5.860	2.113	11.394
1992	3.331	.000	.093	.048	.001	.034	5.870	2.113	11.490
1993	3.361	.000	.094	.048	.001	.034	5.963	2.113	11.614
1994	3.357	.000	.095	.048	.001	.034	5.982	2.113	11.630
1995	3.352	.000	.095	.049	.001	.034	6.175	2.113	11.819
1996	3.350	.000	.095	.049	.001	.034	6.292	2.113	11.934
1997	3.348	.000	.095	.049	.001	.034	6.409	2.113	12.049
1998	3.346	.000	.095	.049	.001	.034	6.529	2.113	12.167
1999	3.344	.000	.094	.048	.001	.034	6.617	2.113	12.251
2000	3.344	.000	.094	.048	.001	.034	6.652	2.113	12.286
				ANNUAL GROWTH RATES					
1981-1990	1.67	.00	¯11.20	2.39	.00	2.25	.78	¯.33	.62
1990-2000	.49	.00	.11	.21	.00	.30	1.50	.00	.93
1981-2000	1.05	.00	¯5.42	1.24	.00	1.22	1.16	¯.15	.78

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,

JUNE 1984

The consumption of oil products is forecast to drop from a level of 0.3 petajoules in 1981 to 0.2 petajoules by 2000 due principally to the decline in heavy fuel oil use on the Island.

5.4 Non-Metallic Minerals Industry

5.4.1 Introduction

The non-metallic minerals industry in British Columbia is dominated by cement manufacturers both in terms of economic output and energy consumption. The remainder of the industry is composed of glass and miscellaneous non-metallic mineral products manufacturers which consume relatively small amounts of energy. The focus of this section, therefore, is on the cement industry which consumes large volumes of natural gas and heavy fuel oil.

5.4.2 Historical Profile

In 1982, two firms, Canada Cement Lafarge and Genstar Cement operated 3 cement plants in B.C. located in Kamloops, Richmond and on Tilbury Island. A fourth plant, operated by Genstar at Bamberton on Vancouver Island was closed in 1981 due to the exhaustion of a readily accessible supply of limestone. This cement plant was relatively old and inefficient and following the decline of previously booming export markets in 1981, the barging of limestone from Texada Island to the Bamberton plant would have resulted in an uneconomic operation.

The manufacture of cement has expanded considerably over the past decade from approximately 0.55 million tonnes in 1970 to 0.97 million tonnes in 1981 at an average annual growth rate of about 5 percent. Provincial cement production peaked in 1979 at 1.35 million tonnes as the U.S. market absorbed 0.85 million tonnes of imports from B.C.. The California market accounted for 0.5 million tonnes in 1979. The export volumes declined to about 0.1 million tonnes in 1981 as a result of significant expansions in cement production capacity on the U.S. west coast.

There are essentially two different technologies employed in cement manufacture in British Columbia. The "wet process" involves the mixing of raw materials in a wet slurry which is subsequently dried, while the "dry process" involves the mixing of materials in a dry state. The Richmond cement plant employs the wet process technology and this process requires the consumption of relatively large volumes of fossil fuels in the drying operation. The dry process employed at both the Kamloops and Tilbury Island plants requires considerably less energy in aggregate than the wet process, although it does consume relatively more electricity.

Table 5.4.1 presents an historical profile of energy consumption within the non-metallic minerals industry. The significant expansion in export sales in 1978 and 1979 leads to the peaking of energy requirements in 1979. The large volume of heavy fuel oil was consumed principally at the Bamberton cement plant.

5.4.3 Industry Production Forecast

The forecast of cement production has been linked to the measure of economic activity in the domestic construction industry and the outlook for exports to the U.S..

The gross domestic product for the construction industry is forecast to increase from 1,292 million (1971) dollars in 1981 to 1,393 million and 1,927 million (1971) dollars in 1990 and 2000, respectively. The relatively lower economic activity in the 1980's reflects the lag between the investment in non-residential structures and economic activity and the reduced residential construction activity associated with lower levels of interprovincial migration and population growth.

TABLE 5.4.1

NON-METALLIC MINERALS INDUSTRY
HISTORICAL ENERGY REQUIREMENTS

(PETAJOULES)

YEAR	NATURAL GAS	COAL AND COKE	HEAVY FUEL OIL	LIGHT FUEL OIL	L.P.G.	DIESEL FUEL OIL	ELECT.	TOTAL REQTS
1971	4.652	.000	3.247	.046	.049	.375	.659	9.028
1972	4.405	.000	2.912	.041	.103	.337	.706	8.504
1973	4.917	.000	3.650	.051	.068	.422	.832	9.940
1974	5.672	.000	3.482	.064	.068	.425	.731	10.443
1975	5.688	.000	3.928	.053	.060	.467	.802	10.998
1976	5.599	.000	3.962	.039	.052	.414	.829	10.894
1977	6.332	.000	3.879	.073	.094	.396	.826	11.600
1978	7.779	.000	3.922	.098	.080	.452	.980	13.311
1979	8.176	.000	4.082	.097	.114	.480	1.138	14.086
1980	8.381	.000	2.623	.077	.073	.514	1.154	12.821
ANNUAL GROWTH RATES								
1971-1980	6.76	.00	-2.34	6.03	4.62	3.55	6.42	3.97

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

Exports of cement to the Pacific Northwest are forecast to recover to about 0.33 million tonnes by 1987 reflecting the increased domestic production capacity and the expected economic recovery. Beyond 1987, exports are forecast to increase at the rate of growth in U.S. GNP as presented in Chapter 2. California is not expected to be a viable market for exports of B.C. cement, and no exports have been assumed to this market throughout the forecast period.

In aggregate, the production of cement is forecast to increase from 1.17 million tonnes in 1981 to 1.49 million tonnes in 1990 and 2.04 million tonnes in 2000.

5.4.4 Forecast of Energy and Fuels Consumption

The forecast of energy requirements is presented in table 5.4.2. It has been prepared by forecasting total energy requirements as a function of the production of cement and applying an exogenous estimate of market shares. It is assumed that energy requirements for the small portion of the industry which is not represented by cement plants will in general grow at the same rate as cement plant requirements.

Total energy consumption is forecast to increase at an average annual rate of about 2.2 percent between 1981 and 1990 and about 2.7 percent between 1990 and 2000.

The forecast assumes that the Richmond cement plant will be converted to the dry process by 1995, and that all incremental productive capacity will also employ the dry process technology. Correspondingly, the electricity share of total energy is forecast to increase significantly from about 10.7 percent from 1981 through 1986 to about 15.6 percent by the year 2000.

TABLE 5.4.2
NON-METALLIC MINERALS SECTOR
ENERGY REQUIREMENTS

(PETAJOULES)

YEAR	NATURAL GAS	COAL AND COKE	HEAVY FUEL OIL	LIGHT FUEL OIL	DIESEL FUEL OIL	L,P,G,	ELECT,	TOTAL REQTS
1978	7.778	.000	3.922	.098	.452	.080	.980	13.310
1979	8.176	.000	4.082	.097	.480	.114	1.138	14.087
1980	8.380	.000	2.622	.077	.513	.073	1.154	12.819
1981	8.415	.000	.741	.058	.384	.055	1.158	10.811
1982	7.699	.000	.678	.053	.351	.050	1.060	9.891
1983	7.691	.000	.678	.053	.351	.050	1.059	9.882
1984	8.252	.000	.727	.057	.377	.054	1.136	10.603
1985	8.526	.393	.786	.061	.407	.058	1.229	11.460
1986	7.434	1.671	.806	.063	.417	.060	1.259	11.710
1987	5.426	3.935	.833	.065	.431	.062	1.301	12.053
1988	3.140	6.490	.862	.067	.447	.064	1.347	12.417
1989	2.280	7.717	.897	.070	.465	.066	1.401	12.896
1990	1.818	8.345	.913	.071	.473	.068	1.470	13.158
1991	1.842	8.456	.925	.072	.479	.068	1.623	13.465
1992	1.882	8.640	.945	.074	.490	.070	1.798	13.899
1993	1.923	8.828	.965	.075	.500	.071	1.982	14.344
1994	1.956	8.980	.982	.077	.509	.073	2.168	14.745
1995	1.990	9.133	.999	.078	.517	.074	2.364	15.155
1996	2.048	9.398	1.028	.080	.532	.076	2.432	15.594
1997	2.100	9.641	1.054	.082	.546	.078	2.495	15.996
1998	2.153	9.883	1.081	.084	.560	.080	2.558	16.399
1999	2.207	10.132	1.108	.087	.574	.082	2.622	16.812
2000	2.255	10.352	1.132	.088	.587	.084	2.679	17.177
ANNUAL GROWTH RATES								
1981-1990	¯15.65	.00	2.35	2.27	2.34	2.39	2.69	2.21
1990-2000	2.18	2.18	2.17	2.17	2.18	2.14	6.19	2.70
1981-2000	¯6.70	.00	2.26	2.22	2.26	2.25	4.51	2.47

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

The industry has been re-examining the possibility of substituting other fuels for natural gas in response to the recent increases in gas prices. In particular, the fluidized bed technology for burning coal or petroleum coke presents a real alternative to natural gas, and some industry officials have suggested that almost all of a plant's current natural gas requirements could be replaced by coal. The substitution of coal for fossil fuels has occurred widely in other jurisdictions. It should be noted that the burning of coal within a cement plant does not present the environmental difficulties experienced in some industries as most of the by-products from the combustion of coal are used as raw materials in cement production.

We have assumed that both Richmond and Kamloops cement plants would install coal burning facilities starting in mid 1985. By 1990 about 85 percent of the natural gas consumption at these two plants would be supplanted by coal. With respect to Genstar's Tilbury Island cement plant, we have assumed that it would also begin using coal in its manufacturing process starting in 1986. Initially about 10 percent of the natural gas use would be displaced by coal at this plant, however, by 1990 about 85 percent of the natural gas use is expected to be displaced by coal. By the year 2000, coal consumption is forecast to reach 10.4 petajoules and represent about 60 percent of the industry's total energy consumption.

The consumption of heavy fuel oil declined substantially from 2.6 petajoules in 1980 to 0.7 petajoules in 1981 when the Bamberton cement plant ceased operation. By the year 2000, consumption is forecast to increase to 1.1 petajoules as heavy fuel continues to be used for periods of natural gas interruption and by glass and miscellaneous non-metallic mineral producers.

Natural gas consumption declines from 8.4 petajoules in 1981 to 2.3 petajoules in 2000 as a result of coal substitution in the cement industry. The share of natural gas declines from 78 percent in 1981 to 14 percent by 1990, the time when all the coal burning facilities in the cement plants become fully operational. In the period following 1990, the natural gas share declines to 13 percent by 2000.

5.5 Petroleum Refining

5.5.1 Introduction

Currently the petroleum and coal products industry includes only petroleum refineries, but at some future date this industry may also include liquefied natural gas (LNG) production. For the purposes of this forecast, however, LNG will be discussed in Chapter 7, rather than in the present section. In 1981, six major oil companies operated seven petroleum refineries in British Columbia; four are located in the Lower Mainland while the remaining three are in Kamloops, Prince George and Taylor. The total capacity of these refineries is 10.12 million cubic metres per year.

The refineries process both B.C. and Alberta crude oil and produce a wide range of products. Provincial refined petroleum product (RPP) requirements are also met by shipments of product from Alberta and, infrequently, from the United States.

5.5.2 Historical Profile

Petroleum refineries consume three types of energy: natural gas, electricity and own-product (fuels produced in the refining process, primarily heavy oil and still gas). The share of electricity has remained small and relatively constant at 5 percent throughout the historical period. Ninety-five percent of refinery energy requirements are heat requirements met from purchased natural gas and own-product. Over the historical period there has been a significant shift away from own-product to natural gas, primarily as a result of the higher market value of own-product relative to that of natural gas. The share of natural gas consequently increased from 3 percent in 1962 to 10 percent in 1975 and 21 percent in 1980.

The reporting of energy consumption by petroleum refineries presents some conceptual difficulties as the refinery is an industrial consumer which produces energy for the final consumer. The consumption of natural gas and electricity are reported as secondary energy consumption and are included in the industrial sector fuel demands while the refinery's own-product use is reported as an energy supply industry consumption used in the calculation of primary crude oil requirements and is not included in the industrial sector fuel demand.

5.5.3 Forecast Period Assumptions

RPP Production

The production of RPP's is forecast as a function of provincial domestic demand (including losses), net inter-regional (and export) transfers, inter-product transfers and inventory changes. The first component is obtained from the summation of the sectoral fuel requirements, while the latter three components reflect the flexibility of the refiners and the impact of effective refinery capacity constraints.

In the forecast period, inventory changes are set equal to zero and interproduct transfers are maintained at the last reported actual level. The level of inter-regional transfers is determined by the relationship between total RPP demand and the ability of the refineries to meet this demand. It is assumed that in the long run, domestic refineries will operate at between 75 and 100 percent of refinery capacity, and if the RPP requirements should present an operating ratio which lies outside of this range an adjustment in the level of inter-regional transfers would take place.[11] The upward bound has been set at 100 percent as refineries are generally built to operate at this capacity continuously and may exceed 100 percent for moderate periods of time. The level of inter-regional transfers is initially set equal to that realized in the previous time period. Transfers of heavy fuel oil are not determined by this mechanism, and only actual heavy fuel oil production associated with domestic light oil production is included as a component of refinery production. The production of heavy fuel oil will be discussed more fully in Chapter 9.

---

[11] The minimum operating ratio is 75 percent. Any shortfall in demand below this level results in export of product. As noted below, this does not occur over the forecast period.

Total throughput, as indicated in Table 5.5.1, is forecast to decline from 361 petajoules in 1981 to levels as low as 321 petajoules during the 1980's and gradually recover to 395 petajoules by 2000 where capacity constraints limit production in that year. The industry maintains a capacity utilization ratio which ranges from a low of about 80 percent during some years in the 1980's to a high of 100 percent achieved in the year 2000 after accounting for capacity changes discussed below.

Because of uncertainty of feedstock supply in the long term, it has been assumed that no further expansions of refinery capacity will occur after 1983. The forecast has allowed for the expansion of the Shell refinery in Burnaby which took place in 1983 to process additional semi-processed synthetic crude from Alberta (an additional 1900 cubic metres per day) and the closure of the Kamloops refinery (1490 cubic metres per day) in May of 1983.

5.5.4 Total Energy and Fuel Requirements Forecast

Energy requirements have been forecast with the aid of the Ministry's energy demand forecasting model where total requirements are related to total throughput and the total price for energy and fuel shares of RPP's and natural gas are allocated on the basis of relative fuel prices.

TABLE 5.5.1

PETROLEUM REFINERY SECTOR

(PETAJOULES)

YEAR	B.C. RPP PRODUCTION	ENERGY REQUIREMENTS OUTPUT PJ	ENERGY REQUIREMENTS INPUT PJ
1978	327.0	18.595	21.844
1979	360.1	20.533	24.405
1980	358.5	19.903	23.737
1981	361.4	19.778	23.475
1982	344.2	16.040	19.227
1983	333.8	15.947	19.124
1984	328.0	16.817	20.174
1985	325.6	16.812	20.171
1986	321.5	16.533	19.839
1987	319.3	16.308	19.573
1988	318.9	16.202	19.449
1989	318.3	16.073	19.298
1990	321.0	16.108	19.353
1991	326.6	16.303	19.595
1992	333.9	16.618	19.977
1993	341.3	16.961	20.389
1994	348.7	17.305	20.804
1995	356.5	17.672	21.245
1996	363.8	18.008	21.649
1997	372.0	18.395	22.115
1998	380.0	18.756	22.548
1999	388.3	19.135	23.005
2000	395.1	19.434	23.365
	ANNUAL GROWTH RATES		
1981-1990	¯1.31	¯2.25	¯2.12
1990-2000	2.10	1.89	1.90
1981-2000	.47	¯.09	¯.02

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

The price associated with oil consumption in determining the fuel market shares is a composite index of the refined product consumption and prices. The index represents the opportunity cost of consuming products which could otherwise be sold and assumes that the opportunity cost of still gas tracks this index.

The price of RPP's is forecast to decline relative to the price of natural gas over the forecast period, leading to a reversal of the historical trend. As a consequence, the market share of refinery fuel supplied by natural gas is forecast to decline from about 21.3 percent in 1980 to 12.1 percent in the year 2000. On the other hand, the market share provided by refinery own-use is forecast to increase from 74.1 percent in 1980 to 83.4 percent in the year 2000.

It should be noted that the production of still gas is forecast to remain relatively constant as a fraction of total RPP throughput, ranging from about 3.4 to 3.7 percent over the forecast period. As well, the proportion of total energy supplied by electricity has been held constant at 5.4 percent in output joules or about 4.5 percent in input energy terms.

Energy consumption is determined as a function of total throughput excluding the production of heavy fuel oil and petroleum coke. These latter two products are residual and their yield is in fact inversely related to the intensity of energy employed within the refinery. The production of heavy fuel oil is discussed separately in Chapter 9. The domestic production of petroleum coke, however, is quite modest and mostly it is consumed within the producing refineries.

Total energy requirements, as reported in Table 5.5.2, are forecast to decline during the 1980's from a level of 23.6 petajoules in 1981 to 19.4 petajoules in 1990. Following this decline, the requirements are expected to increase principally as a result of increased RPP production. However, some of the fuel requirements associated with the increased RPP production are expected to be offset by fuel savings through increased conservation attributable to higher energy prices.

The consumption of natural gas is forecast to decline modestly from 5.3 petajoules in 1981 to 2.8 petajoules in 2000, resulting, as noted above, from a shift towards the increased consumption of refinery own-product use.

Both refinery own-product use and electricity exhibit growth patterns which cause consumption in 2000 at virtually the same levels achieved in 1981.

5.6 Petrochemicals

5.6.1 Introduction

The term petrochemicals has been defined rather broadly here to include the production of both petrochemicals and liquefied natural gas (LNG). As noted elsewhere, petrochemicals are generally included in the Standard Industrial Classification under chemicals while liquefied natural gas is generally classified under petroleum and coal products. While we have

TABLE 5.5.2

PETROLEUM REFINERY SECTOR
ENERGY REQUIREMENTS

(PETAJOULES)

YEAR	DIESEL FUEL OIL	HEAVY FUEL OIL	LIGHT FUEL OIL	MOTOR GASOLINE	PETROLEUM COKE	STILL GAS	TOTAL OWN-USE	NATURAL GAS	ELECT,	TOTAL REQTS
1978	.275	.797	.027	.017	1.564	13.221	15.901	4.912	1.031	21.844
1979	.692	.810	.023	.014	1.755	14.887	18.181	5.183	1.041	24.405
1980	.831	1.031	.023	.000	1.754	13.951	17.590	5.068	1.079	23.737
1981	.808	.530	.015	.000	1.864	13.995	17.212	5.333	1.072	23.617
1982	.758	.947	.015	.066	1.877	10.812	14.475	3.883	.869	19.227
1983	.765	.956	.015	.066	1.894	10.908	14.604	3.656	.864	19.124
1984	.818	1.022	.016	.071	2.025	11.665	15.617	3.646	.911	20.174
1985	.820	1.025	.016	.071	2.031	11.695	15.658	3.602	.911	20.171
1986	.813	1.016	.016	.071	2.013	11.596	15.525	3.418	.896	19.839
1987	.808	1.009	.016	.070	2.000	11.519	15.422	3.267	.884	19.573
1988	.807	1.009	.016	.070	2.000	11.517	15.419	3.152	.878	19.449
1989	.806	1.007	.016	.070	1.996	11.497	15.392	3.035	.871	19.298
1990	.825	1.031	.017	.072	2.043	11.769	15.757	2.723	.873	19.353
1991	.847	1.058	.017	.074	2.097	12.079	16.172	2.539	.884	19.595
1992	.869	1.085	.017	.075	2.151	12.388	16.585	2.491	.901	19.977
1993	.887	1.109	.018	.077	2.198	12.658	16.947	2.523	.919	20.389
1994	.906	1.132	.018	.079	2.243	12.918	17.296	2.570	.938	20.804
1995	.925	1.156	.019	.080	2.291	13.194	17.665	2.622	.958	21.245
1996	.943	1.179	.019	.082	2.336	13.453	18.012	2.661	.976	21.649
1997	.964	1.205	.019	.084	2.387	13.749	18.408	2.710	.997	22.115
1998	.983	1.229	.020	.085	2.435	14.026	18.778	2.753	1.017	22.548
1999	1.004	1.255	.020	.087	2.486	14.320	19.172	2.796	1.037	23.005
2000	1.020	1.275	.020	.089	2.527	14.553	19.484	2.828	1.053	23.365
ANNUAL GROWTH RATES										
1981-1990	.23	7.67	1.40	.00	1.02	¯1.91	¯.98	¯7.20	¯2.26	¯2.19
1990-2000	2.14	2.15	1.64	2.14	2.15	2.15	2.15	.38	1.89	1.90
1981-2000	1.23	4.73	1.53	.00	1.61	.21	.65	¯3.28	¯.09	¯.06

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

continued to use this classification, three major Petrochemical/LNG projects have been identified and are discussed separately in this chapter since they consume major amounts of fuel resources.

Natural gas use identified for these three major projects is consumed principally as a feedstock in the manufacturing process and will consequently be considered a non-energy consumption included in Chapter 7.[12] Electricity consumption, however, is included as a fuel requirement within the industrial sector.

5.6.2 Industry Production Forecast

The Ocelot methanol plant at Kitimat became the first major petrochemical project in British Columbia with the opening of its facilities in 1982. Ocelot consumed about 5.7 petajoules of natural gas in its first year of operation and is expected to consume about 12.7 petajoules of natural gas annually under normal operating conditions.

In 1982, a Commissioner Inquiry established a set of criteria for determining the existence and the extent of a natural gas surplus, and the estimation of the volume of natural gas which could reasonably be allocated to export and new industrial projects.[13] The government then undertook an evaluation process to determine how this surplus could be allocated with the greatest benefits to the province. In a statement by the Minister of Energy,[14] it was announced that, based on the anticipated drilling activity, B.C. would have a surplus of 3 trillion cubic feet (3,290 petajoules) of natural gas which could be allocated to export and new industrial projects. Of this total, 1.8 trillion cubic feet (1,970 petajoules) was allocated to the U.S. export market over an eight year time period, 0.8 trillion cubic feet (880 petajoules) to an LNG facility and 0.4 trillion cubic feet (440 petajoules) to an ammonia-urea project. The last two volumes were set aside to be consumed over a twenty year time period.

---

[12] A relatively small amount of gas is expected to be used at the LNG plant and at the compressor stations for transmitting the gas through pipelines. These amounts are included in the estimates reported in Chapter 7.

[13] "Commissioner Inquiry on British Columbia's Requirements, Supply and Surplus of Natural Gas and Natural Gas Liquids", George W. Govier, Victoria, 1982

The LNG project selected by the province is expected to consume about 170 petajoules of natural gas at full production levels and the province has made a commitment to provide up to 50 percent of the total requirements. The provision of natural gas to this project, however, is contingent upon the negotiation of a pricing arrangement between the producers and the consortium. The remainder of the natural gas requirements not supplied by B.C. are expected to be met with production from Alberta. The project is expected to begin operations in 1987 and attain full production levels by 1989.

---

[14] Hon. R. H. McClelland, July 15, 1982.

Twenty billion cubic feet (22 petajoules) of natural gas have been set aside annually for the operation of an ammonia-urea facility. While a number of proposals have been made for the use of this gas, the province has not yet selected a preferred project. it is assumed here that a proposal will be advanced and that this project will begin consuming gas in 1987.

5.6.3 Forecast of Energy Consumption

The Ocelot methanol facility is expected to consume about 0.14 petajoules of electricity annually at full production. The electricity requirements of the 20 bcf ammonia-urea project are expected to be 0.19 petajoules per year.

The Western LNG facility is scheduled to require 3.72 petajoules of electricity at full production, and it is anticipated that B.C. Hydro will have the necessary generation and transmission facilities in place to meet the full electricity requirements of the LNG plant.

A summary of the electricity requirements for the production of petrochemicals and LNG is presented in Table 5.6.1.

5.7 Other Manufacturing

5.7.1 Introduction

The "other manufacturing" industry is defined to include all manufacturing industries not previously considered and is composed primarily of relatively small firms engaged in light manufacturing.[1] For the most part, members of this industry are located in the Lower Mainland.

---

[1] This group includes Food and Beverages (including fish), Rubber and Plastic, Clothing related and leather, Furniture and Fixtures, Printing and Publishing, Metal Fabricating, Machinery, Transport Equipment and Miscellaneous Manufacturing.

TABLE 5.6.1

PETROCHEMICAL SECTOR
ELECTRICITY REQUIREMENTS

(PETAJOULES)

YEAR	LIQUEFIED NAT. GAS	PETRO-CHEMICALS	TOTAL ELECTRICITY
1978	.000	.000	.000
1979	.000	.000	.000
1980	.000	.000	.000
1981	.000	.000	.000
1982	.000	.061	.061
1983	.000	.128	.128
1984	.000	.137	.137
1985	.000	.137	.137
1986	.000	.137	.137
1987	.000	.256	.256
1988	2.819	.327	3.146
1989	3.396	.327	3.723
1990	3.524	.327	3.851
1991	3.716	.327	4.043
1992	3.716	.327	4.043
1993	3.716	.327	4.043
1994	3.716	.327	4.043
1995	3.716	.327	4.043
1996	3.716	.327	4.043
1997	3.716	.327	4.043
1998	3.716	.327	4.043
1999	3.716	.327	4.043
2000	3.716	.327	4.043

ANNUAL GROWTH RATES

1981-1990	.00	.00	.00
1990-2000	.53	.00	.49
1981-2000	.00	.00	.00

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

5.7.2 Historical Profile

In terms of gross domestic product, the food and beverage industry was the largest single component of other manufacturing in 1980, representing 26 percent of the total, with metal fabrication, transportation equipment, printing and publishing and machinery combining to produce 50 percent of the total. The other manufacturing industry realized an average annual growth rate of 5.2 percent in GDP between 1971 and 1980.

Table 5.7.1 presents the profile of energy consumption for the components of the other manufacturing industry in 1980. The food and beverage industry used about 57 percent of the total energy consumed, accounting for 61 percent of the natural gas, 72 percent of the oil, and 43 percent of electricity consumption. The metal fabrication industry consumed about 17 percent of total energy.

Natural gas accounted for about 60 percent of total energy consumption in 1980 while electricity and oil products contributed about 27 and 13 percent, respectively.

Between 1971 and 1980, total energy consumption grew at an average annual rate of 3.3 percent. This rate is considerably lower than the 5.2 percent average annual rate reported for economic activity in the other manufacturing industry as a whole. The divergence between growth in economic activity and energy consumption is in part explained by the different growth rates experienced by subcomponents of the industry. The food and beverage industry, which consumed 0.02 petajoules of energy for each one million (1971) dollars of GDP in 1980, experienced an average annual economic growth rate of 1.9 between 1971 and 1980, while the remainder of the industry, which consumed 0.005

TABLE 5.7.1

1980 PROFILE OF THE OTHER MANUFACTURING INDUSTRY

INDUSTRY	G.D.P. (MM 1971 $)	ENERGY CONSUMPTION (PETAJOULES) NATURAL GAS	OIL	ELECTRICITY	TOTAL
FOOD AND BEVERAGE	296	3.955	1.014	1.239	6.208
METAL FABRICATION	187	1.159	.140	.527	1.826
TRANSPORT EQUIPMENT	147	.346	.113	.245	.703
PRINTING + PUBL'N	127	.107	.026	.206	.339
MACHINERY	119	.464	.059	.338	.861
OTHER	275	.469	.051	.344	.863
TOTAL	1151	6.500	1.403	2.896	10.801

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

petajoules of energy for each one million (1971) dollars of GDP in 1980, grew at an average annual rate of 6.6 percent over the same time period.

5.7.3 Forecast Period Assumptions

Industry Production

The food and beverage industry is forecast to grow at an average annual rate of 1.0 percent between 1981 and 1990, and 2.6 percent during the 1990's (see also Table 2.6). The corresponding growth rates for the non-food component are 1.4 and 4.4 percent and these rates are assumed to apply to the remainder of the other manufacturing industries classification. The growth in the non-food other manufacturing industry is consistent with a desire to pursue a path of industrial diversification and increasing reliance upon the benefits obtained from high technology.

5.7.4 Total Energy and Fuel Requirements Forecast

Energy requirements for the other manufacturing industry are forecast to move in relation to the economic activity in the industry. The share of these energy requirements met by each fuel is estimated as a function of relative energy prices and other economic information.

Total energy requirements, as reported in Table 5.7.2, are forecast to increase from 10.8 petajoules in 1980 to 12.8 petajoules in 1990 and 17.1 petajoules in 2000. This represents an average annual growth rate of 1.7 percent between 1980 and 1990 and 3.0 percent during the 1990's.

Natural gas remains the single most important fuel rising from 6.5 petajoules in 1980 to 10.4 petajoules in 2000. The Vancouver Island gas pipeline contributes 0.4 petajoules to the total in 1986 and 0.8 petajoules by the year 2000. The introduction of natural gas service to Vancouver Island is forecast to result in displacement of 0.2 petajoules of LPG's, 0.4 petajoules of light fuel oil and 0.2 petajoules of heavy fuel oil by the year 2000.

The market share of refined petroleum products is projected to rise modestly from 12.9 percent in 1980 until the Vancouver Island pipeline is completed, but then decline to 11.9 percent in the year 2000. In aggregate, the consumption of refined petroleum products increases at an average annual rate of 1.9 percent from 1.4 petajoules in 1980 to 2.0 petajoules in the year 2000.

The market share of electricity is expected to remain almost constant over the forecast period despite the more rapid growth of the non-food component of the industry and its lower level of electricity intensity. Over the forecast period, electricity requirements increase from about 2.9 petajoules in 1980 to 4.6 petajoules in 2000 at an average annual growth rate of 2.4 percent.

TABLE 5.7.2

OTHER MANUFACTURING SECTOR
ENERGY REQUIREMENTS

(PETAJOULES)

YEAR	NATURAL GAS	COAL AND COKE	HEAVY FUEL OIL	LIGHT FUEL OIL	DIESEL FUEL OIL	L.P.G.	ELECT.	TOTAL REQTS
1978	5.769	.000	.632	.298	.384	.113	2.474	9.670
1979	6.010	.000	.543	.293	.426	.110	2.599	9.981
1980	6.507	.010	.538	.275	.459	.124	2.905	10.818
1981	7.011	.010	.546	.273	.467	.122	3.044	11.473
1982	6.319	.009	.490	.243	.418	.108	2.722	10.309
1983	6.271	.009	.483	.240	.413	.107	2.700	10.223
1984	6.428	.009	.507	.253	.433	.113	2.789	10.532
1985	6.706	.010	.551	.275	.471	.123	2.931	11.067
1986	7.198	.011	.477	.074	.509	.033	2.985	11.287
1987	7.301	.012	.516	.081	.550	.036	3.053	11.549
1988	7.482	.013	.561	.088	.599	.039	3.157	11.939
1989	7.685	.014	.609	.096	.650	.043	3.265	12.362
1990	7.873	.015	.653	.103	.697	.046	3.369	12.756
1991	8.094	.016	.690	.109	.736	.049	3.485	13.179
1992	8.347	.017	.718	.114	.765	.051	3.611	13.623
1993	8.618	.017	.741	.118	.791	.053	3.743	14.081
1994	8.900	.018	.765	.122	.815	.055	3.879	14.554
1995	9.193	.019	.788	.127	.840	.057	4.021	15.045
1996	9.441	.019	.809	.130	.862	.059	4.141	15.461
1997	9.696	.020	.829	.134	.883	.060	4.264	15.886
1998	9.960	.020	.850	.138	.906	.062	4.392	16.328
1999	10.198	.021	.869	.142	.926	.064	4.513	16.733
2000	10.427	.021	.888	.145	.945	.065	4.628	17.119
ANNUAL GROWTH RATES								
1981-1990	1.30	4.61	2.01	¯10.26	4.55	¯10.27	1.13	1.18
1990-2000	2.85	3.42	3.12	3.48	3.09	3.52	3.23	2.99
1981-2000	2.11	3.98	2.59	¯3.28	3.78	¯3.26	2.23	2.13

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

5.8 Mining

5.8.1 Introduction

The mining industry in British Columbia is comprised of open-pit and underground mines producing coal, copper, lead, zinc, molybdenum, gold, silver, and other metallic and non-metallic minerals, and has been dominated since the late 1960's by large scale coal and copper open-pit operations. Metal mines are relatively more energy intensive than coal mines, and consume primarily electricity and diesel fuel oil. The mining of metallurgical coal, however, requires large volumes of natural gas for coal drying.

The energy requirements forecast presented in this section is developed with key emphasis on production activity for the metals, copper, lead, zinc and iron and for coal, both thermal and metallurgical.

5.8.2 Historical Profile

Table 5.8.1 presents the historical profile of energy consumption[16] by the mining industry from 1962 to 1980.

The major increase in natural gas consumption reported in the early 1970's is principally due to the opening of coal mines in the southeast of the Province. These operations consume natural gas to dry metallurgical coal before export.

---

[16] Statistics Canada, private communication:
"The refined petroleum products are disaggregated by individual products only after 1972 and the distribution of oil products for years earlier than 1973 is the same as that reported for 1973. There appears to be a problem with the oil number reported for 1967.

TABLE 5.8.1

MINING INDUSTRY HISTORICAL ENERGY REQUIREMENTS

(PETAJOULES)

YEAR	NATURAL GAS	COAL AND COKE	HEAVY FUEL OIL	LIGHT FUEL OIL	L.P.G.	DIESEL FUEL OIL	ELECT.	TOTAL REQTS
1962	.741	.000	.459	.380	.019	.868	.623	3.090
1963	.593	.000	.507	.420	.022	.960	1.339	3.841
1964	.312	.000	.470	.389	.034	.889	1.310	3.404
1965	.265	.000	.552	.457	.038	1.046	2.419	4.777
1966	.416	.000	.604	.500	.038	1.143	1.876	4.577
1967	.490	.000	.091	.075	.064	.172	2.171	3.064
1968	.533	.000	.581	.481	.063	1.099	2.567	5.324
1969	.574	.000	.751	.622	.073	1.422	2.686	6.126
1970	1.540	.000	1.114	.922	.144	2.109	3.571	9.400
1971	1.770	.000	1.545	1.279	.180	2.925	4.187	11.886
1972	3.568	.000	1.896	1.570	.321	3.589	6.919	17.864
1973	3.616	.000	2.048	1.696	.278	3.878	9.266	20.782
1974	3.967	.000	2.602	1.186	.277	3.958	7.697	19.687
1975	4.207	.000	2.348	.782	.240	4.540	7.674	19.792
1976	3.918	.000	1.818	.193	.211	5.539	7.573	19.253
1977	3.644	.000	1.680	.256	.219	6.000	8.543	20.342
1978	4.066	.000	1.182	.224	.228	5.900	8.854	20.454
1979	4.423	.000	.580	.220	.249	6.647	9.133	21.253
1980	4.371	.000	.651	.140	.246	7.575	9.695	22.679
ANNUAL GROWTH RATES								
1962-1970	9.58	.00	11.73	11.73	28.37	11.73	24.40	14.92
1970-1980	10.99	.00	¯5.23	¯17.20	5.54	13.64	10.50	9.21

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

Electricity requirements grew substantially over the historical period from 3.6 petajoules in 1970 to 9.7 petajoules in 1980. Much of this increase was associated with the opening of major new copper/molybdenum operations in the early 1970's and it has been estimated that copper/molybdenum producers consumed about 75 percent of the total electricity requirements of the mining industry in 1980.[17]

Refined petroleum products have declined in importance in meeting the industry's energy requirements over time, with market share falling from 46 percent in 1970 to 38 percent in increased substantially in recent years rising from 22 percent of total energy requirements in 1970 to 33 percent in 1980 due to the increased activity in metal mining operations.

In 1979, copper, lead/zinc and iron products accounted for about 99 percent of the total volume of metal production and about 61 percent of value.[18]

Metalluragical coal production currently accounts for approximately 90 percent of total coal production in the Province, with the remaining 10 percent being thermal coal. Metallurgical coal is used in the production of coke for the steel making process and the major portion of British Columbia production is destined for Pacific Rim markets, essentially Japan and Korea. Thermal coal is also exported principally to Pacific Rim nations.

---

[17] "British Columbia Energy Supply and Requirements 1980-1995," MEMPR, April 1981.

[18] The production of molybdenum, gold and silver accounted for 23.8, 7.7 and 7.0 percent of the total value of metal mining in 1979, respectively. These minerals are often jointly produced with the above noted minerals and, for this reason, have been excluded from the forecast of production of important driving variables for energy requirements.

5.8.3 Industry Production Forecast

The outlook for economic activity in the mining sector has been summarized in Chapter 2. Gross domestic product in the metallic minerals industry has been forecast to grow slowly from 234 million (1971) dollars in 1981 to 241 million (1971) dollars in 1990 and then to increase at the rate of 2.9 percent per annum to 321 million (1971) dollars in the year 2000. In contrast, GDP in the coal mining industry is forecast to increase at an average annual rate of 6.1 percent from 69 million (1971) dollars to 118 million (1971) dollars in 1990 and 174 million (1971) dollars in 2000.

The forecast of gross domestic product has been produced by analyzing both the markets which consume the mineral products, and the ability of the province to provide these resources. The Province has sufficient reserves of minerals to more than accommodate the forecast of economic activity presented above.

Production of copper is forecast to grow very little until 1987 and then to increase at 1.5 percent per annum from 300 thousand tonnes in 1987 to 364 thousand tonnes in 2000 (Table 5.8.2). Lead/zinc production experiences erratic growth until 1985 but thereafter increases at the rate of 1.8 percent per annum.

Both copper production and prices have been depressed for some time. It is expected that prices will recover on the strength of an upturn in the U.S. economy and that copper production will fluctuate in response to general economic conditions. In the 1990's, it is expected that the world supply/demand balance for copper will require the construction of additional productive capacity and British Columbia is expected to provide a portion of that capacity. There appears to be particularly strong potential for the development of new mines in the northwest of the province.

TABLE 5.8.2

FORECAST MINERAL PRODUCTION IN BRITISH COLUMBIA

(THOUSANDS OF TONNES)

YEAR	COPPER	IRON ORE	LEAD/ ZINC	METALLURGICAL COAL	THERMAL COAL
1978	274	616	190	8530	934
1979	272	668	184	9592	978
1980	265	668	155	9654	1169
1981	290	634	164	10823	914
1982	280	775	159	9600	2282
1983	286	487	207	9600	2300
1984	285	0	235	16700	3900
1985	315	0	250	19400	5400
1986	310	0	215	19000	6100
1987	300	0	219	19000	6100
1988	305	0	223	19000	6100
1989	309	0	227	19000	6100
1990	314	0	231	19000	6100
1991	318	0	235	19000	6100
1992	323	0	239	19000	6100
1993	328	0	244	19000	6100
1994	333	0	248	19000	6100
1995	338	0	252	19000	6100
1996	343	0	257	19000	6100
1997	348	0	262	21500	8100
1998	353	0	266	21500	8100
1999	359	0	271	21500	8100
2000	364	0	276	21500	8100
ANNUAL GROWTH RATES					
1981-1990	.88	.00	3.87	6.45	23.48
1990-2000	1.50	.00	1.80	1.24	2.88
1981-2000	1.20	.00	2.78	3.68	12.17

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

The forecast assumes that only one new major copper mining property will be developed in the province by the turn of the century. The Kutcho Creek property is assumed to produce 72,000 tonnes of copper concentrate and about 66,000 tonnes of zinc concentrate, and would be phased to full production after commencement of operations in 1990.

The production of lead and zinc is expected to follow the same trends as copper production. The forecast would require the development of a new lead/zinc operation in the province with the most likely candidate being the Cirque property north of Williston Lake which may be developed by the late 1980's.

The Wesfrob property on the Queen Charlotte Islands and the Craigmont mine in the Highland Valley produced virtually all of the Province's iron ore. These mines are now closed because of reserves depletion.

Strong growth in coal mining activity translates into production at levels of about 25.1 million tonnes by 1990 and 29.6 million tonnes by the year 2000.

The world recession and the ensuing oversupply in the Japanese coking coal markets have resulted in production cutbacks at several southeastern British Columbia mines and these mines are not expected to recover to their 1980/81 levels until around 1986. The northeast coal mines have established long term contracts with Japanese steel firms and should be able to sell contracted volumes. In the long run, British Columbia is in a very strong position to increase its shipments of metallurgical coal as it possesses a reputation as a reliable supplier and will have developed the infrastructure required to increase its share of the expanding Pacific Rim coal trade.

The production of metallurgical coal is forecast to increase from 10.8 million tonnes in 1981 to 19.0 million tonnes in 1990 and 21.5 million tonnes in the year 2000. Production from the northern part of the province is projected to constitute about 37 percent of the total by 1990 and 50 percent by the year 2000.

The market for thermal coal is expected to expand rapidly as British Columbia provides coal principally for electricity generation within Pacific Rim nations. In addition, provision has been made for the development of up to 3 million tonnes of anthracite coal from the large Groundhog deposit in north-western British Columbia for export to South Korea and Europe. It is projected that thermal coal will increase its share of total production from about 24 percent in 1990 to 27 percent by the year 2000. Thermal coal production is forecast to increase from 0.9 million tonnes in 1981 to 6.1 million tonnes in 1990 and 8.1 million tonnes in the year 2000.

5.8.4 Forecast of Energy and Fuels Consumption

Energy consumption by the mining industry in British Columbia was forecast using the methodology outlined in the Ministry's Staff Paper.[19] Market shares held by each fuel were determined as well as the total amount of energy consumed by the industry. The impacts of the use of refuse coal in coal driers (displacing natural gas) and the consumption of electricity in regions which do not have access to the integrated electricity grid were also considered.[20]

---

[19] "The B.C. Energy Demand Forecasting and Planning Model" Staff Paper; March, 1983.

The electricity requirements for the new northwest mines (Kutcho Creek and Klappan) are projected to rise from 0.9 petajoules in 1990 to 2.3 petajoules by the year 2000. A preliminary cost analysis suggests that these mines are sufficiently distant from the existing integrated grid to preclude transmission from the grid as an economic electricity supply. Therefore, the electricity requirements of the Kutcho Creek property is assumed to be provided by diesel generators. The Klappan coal project which is expected to come on stream in 1990 is assumed to be supplied with electricity from a new coal fired generating station.

By 2000, the electricity requirements of the northwest mines are met by 0.5 petajoules from coal fired facilities, and the remaining 1.7 petajoules from diesel generators. These requirements have been excluded from the calculation of total electricity requirements on the B.C. Hydro system.

The northwest mines are assumed to have no access to natural gas service, and their estimated requirements of non-electric energy have been met by petroleum products.

---

[20] As mentioned earlier, the industrial energy data does not include estimates of the quantity of electricity generated from fossil fuels by the mining industry. These energy requirements are reported as fossil fuel demand rather than as electricity generation and consumption. Electricity requirements for new mines developed in the northwest are assumed to be met by hydro, diesel and coal.

The metallurgical coal mines in the northeast have announced their decision to consume refuse coal in their drying units, displacing natural gas. About 87 percent of the estimated natural gas load of these mines has been assumed to be displaced with refuse coal.

Table 5.8.3 presents the forecast of energy requirements for the mining industry. Total energy requirements are forecast to increase from 23.7 petajoules in 1981 to 39.3 petajoules in 2000, at an average annual rate of 2.7 percent.

The consumption of electricity is forecast to increase from 11.3 petajoules in 1981 to 12.4 petajoules in 2000 which represent an average annual increase of 0.5 percent.

The share of total energy requirement supplied by natural gas declines from 21 percent in 1981 to 9 percent in the year 2000, principally because the northeast coal mines are expected to burn refuse coal rather than natural gas in their coal driers, and the northwest mines are expected to have no access to natural gas service. In total, the natural gas requirements decline from 5.1 petajoules in 1981 to 3.4 petajoules in 2000.

The consumption of diesel fuel oil is forecast to increase from 5.4 petajoules in 1981 to 14.3 petajoules in 2000. In the year 2000, approximately 2.0 petajoules of this total is consumed by new northwest mines for the generation of electricity.

Heavy fuel oil consumption is projected to increase from 0.6 petajoules in 1981 to 1.6 petajoules as the price of heavy fuel oil escalates less rapidly than the price of natural gas in the northeast area and as the northwest mines are assumed to have no access to natural gas.

TABLE 5.8.3
MINING SECTOR
ENERGY REQUIREMENTS

(PETAJOULES)

YEAR	NATURAL GAS	COAL AND COKE	HEAVY FUEL OIL	LIGHT FUEL OIL	DIESEL FUEL OIL	L.P.G.	ELECT.	SELF-GEN ELECTRICITY	TOTAL REQTS
1978	4.064	.000	1.182	.224	5.897	.228	8.850	.000	20.445
1979	4.421	.000	.580	.220	6.644	.249	9.129	.000	21.243
1980	4.364	.000	.632	.240	7.238	.271	9.701	.000	22.446
1981	5.063	.000	.557	.212	6.381	.239	11.265	.000	23.717
1982	4.153	.000	.523	.199	5.993	.225	10.918	.000	22.011
1983	4.092	.000	.501	.190	5.740	.215	11.001	.000	21.739
1984	5.419	2.458	.513	.195	5.879	.220	12.629	.000	27.313
1985	5.973	3.340	.620	.236	7.103	.266	14.601	.000	32.139
1986	5.338	3.690	.641	.243	7.337	.275	14.321	.000	31.845
1987	5.401	3.663	.650	.247	7.443	.279	14.067	.000	31.750
1988	5.379	3.633	.665	.253	7.615	.285	14.082	.000	31.912
1989	5.354	3.598	.670	.254	7.672	.288	14.130	.000	31.966
1990	3.852	4.341	.959	.234	10.010	.264	11.965	.000	31.625
1991	3.627	4.308	1.173	.238	11.895	.269	11.457	.000	32.967
1992	3.473	4.288	1.317	.244	13.195	.276	11.144	.000	33.937
1993	3.351	5.120	1.427	.250	13.330	.282	10.925	.000	34.685
1994	3.281	5.618	1.486	.253	13.411	.285	10.867	.000	35.201
1995	3.235	5.948	1.525	.256	13.513	.289	10.865	.000	35.631
1996	3.231	5.944	1.522	.259	13.619	.293	10.976	.000	35.844
1997	3.381	6.972	1.627	.275	14.095	.311	12.080	.000	38.741
1998	3.380	6.964	1.622	.278	14.172	.314	12.200	.000	38.930
1999	3.378	6.955	1.617	.280	14.250	.316	12.322	.000	39.118
2000	3.375	6.946	1.612	.282	14.336	.319	12.443	.000	39.313
					ANNUAL GROWTH RATES				
1981-1990	¯2.99	.00	6.22	1.10	5.13	1.11	.67	.00	3.25
1990-2000	¯1.31	4.81	5.33	1.88	3.66	1.91	.39	.00	2.20
1981-2000	¯2.11	.00	5.75	1.51	4.35	1.53	.52	.00	2.70

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,

JUNE 1984

5.9 Other Industrial Sector

5.9.1 Introduction

The other industrial is a residual category, defined to include principally primary forestry (logging) and construction. Historical energy consumption for the other industrial sector was determined residually.[23]

5.9.2 Historical Profile

There is not much historical information available on the energy consumption of the logging and construction industries. The Ministry's estimates for the period 1973 to 1979 are reported in Table 5.9.1.[24] Total energy consumption was made up primarily by diesel fuel oil. Apart from a dip in 1975 caused by a strike in the forest industry, diesel fuel requirements have grown modestly over the period.

---

[23] Requirements were calculated as the statistical difference between one; the sum of the requirements of the manufacturing and mining subsector from the "Consumption of Purchased Fuel and Electricity by Manufacturing, Mining, Logging and Electric Power Industries" and reported self-generated hydroelectricity and two; the total industrial requirements from the "Quarterly Report on Energy Supply-Demand in Canada and Detailed Energy Supply Demand in Canada."

[24] The figures reported in Table 5.9.1 are not the residual numbers referred to in the previous footnote, but are separate estimates prepared by the Ministry.

TABLE 5.9.1

Historical Energy Requirements for the Logging and Construction Industries[*]

(petajoules)

	Natural[**] Gas	Heavy Fuel Oil	Light Fuel Oil	Diesel Fuel Oil	Purchased Electricity	Total Reqts.
1973	NA	4.13	0.91	14.47	0.10	19.61
1973	NA	4.01	0.80	14.24	0.10	19.15
1975	NA	3.91	0.50	10.96	0.11	15.48
1976	NA	0.75	0.45	14.06	0.11	15.37
1977	NA	1.04	0.69	15.28	0.12	17.13
1978	0.04	0.96	0.75	15.90	0.12	17.77
1979	0.04	1.15	1.27	16.64	0.12	19.22

---

[*] "British Columbia Energy Supply and Requirements Forecast, 1980-1995," MEMPR, April, 1981, Tables 3.77 and 4.24.

[**] The estimates are for the construction industry on the lower Mainland only.

Heavy fuel oil consumption has declined dramatically and following a decline in the early years light fuel oil appears to be on the increase. Electricity requirements, on the other hand, have continued to grow modestly.

5.9.3 Forecast Period Assumptions

Diesel fuel requirements were separated into logging and construction and each component was forecast separately. Logging requirements were assumed to grow at the same rate as production in the logging industry, while construction requirements grow at the same rate as construction GDP.

Activity in the logging industry , as measured by total lumber production , is expected to increase at an average annual rate of 1.1 percent between 1981 and the year 2000 (see Table 5.1.13). On the other hand, the construction industry, which accounted for less than 25 percent of the diesel requirements in 1979, is assumed to grow at an average annual rate of 2.1 percent as reported in Table 2.5 of chapter 2.

5.9.4 Total Energy and Fuel Requirements Forecast

Based on the above assumptions, it is anticipated that total energy requirements will increase at an average annual rate of 1.2 percent between 1981 and the year 2000. This is reflected by the growth in diesel fuel requirements which reach 24 PJ by the year 2000. No attempt was made to define growth patterns for the remaining fuel sources because of their very low shares. The requirements forecast is reported in Table 5.9.2.

TABLE 5.9.2

OTHER INDUSTRIAL SECTOR ENERGY REQUIREMENTS

(PETAJOULES)

YEAR	NATURAL GAS	HEAVY FUEL OIL	LIGHT FUEL OIL	DIESEL FUEL OIL	ELECT,	TOTAL REQTS
1978	.040	.993	.750	15.900	.120	17.803
1979	.040	1.152	1.270	16.640	.120	19.222
1980	.040	.513	.750	19.925	.120	21.348
1981	.040	.075	.750	18.827	.120	19.812
1982	.040	.075	.750	17.906	.120	18.891
1983	.040	.075	.750	19.073	.120	20.058
1984	.040	.075	.750	19.602	.120	20.587
1985	.040	.075	.750	20.192	.120	21.177
1986	.040	.075	.750	19.574	.120	20.559
1987	.040	.075	.750	19.777	.120	20.762
1988	.040	.075	.750	20.418	.120	21.403
1989	.040	.075	.750	20.709	.120	21.694
1990	.040	.075	.750	20.869	.120	21.854
1991	.040	.075	.750	21.267	.120	22.252
1992	.040	.075	.750	21.884	.120	22.869
1993	.040	.075	.750	22.224	.120	23.209
1994	.040	.075	.750	22.550	.120	23.535
1995	.040	.075	.750	22.797	.120	23.782
1996	.040	.075	.750	23.049	.120	24.034
1997	.040	.075	.750	23.273	.120	24.258
1998	.040	.075	.750	23.503	.120	24.488
1999	.040	.075	.750	23.740	.120	24.725
2000	.040	.075	.750	23.940	.120	24.925

ANNUAL GROWTH RATES

1981-1990	.00	.00	.00	1.15	.00	1.10
1990-2000	.00	.00	.00	1.38	.00	1.32
1981-2000	.00	.00	.00	1.27	.00	1.22

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

CHAPTER 6
TRANSPORTATION SECTOR

6.0 Transportation Sector Overview

6.0.1 Introduction

Requirements for four modes of transportation activity (road, rail, marine and air) are included in this sector. Each mode is discussed separately in sections 6.1 through 6.4.

By 1981, transportation accounted for almost 72 percent of all refined petroleum product (RPP) requirements in B.C. while within the transportation group, road requirements accounted for almost 70 percent. Motor gasoline is the principal fuel in the transportation sector, contributing almost 58 percent of total requirements in 1981.

The dramatic increases in RPP prices in the 1979 to 1982 period, resulting from the world oil crisis in 1979 and the implementation of the National Energy Program in 1980, are expected to dampen requirements growth over the eighties. Indeed, when coupled with slow economic performance between 1982 and 1984, transportation sector requirements excluding those of heavy fuel oil have declined by 11.7 percent since 1981 as summarized in Table 6.0.1.

It is anticipated that a surge in economic growth during the nineties will be sufficient to result in some marginal growth in total requirements for the whole forecast period. Motor gasoline requirements, however, are expected to decline from their historical peak in 1980 as they are displaced through improvements in engine efficiencies, substitution of diesel fuel and alternatives such as propane and natural gas.

TABLE 6.0.1
TOTAL TRANSPORTATION ENERGY REQUIREMENTS

(PETAJOULES)

YEAR	NATURAL GAS	HEAVY FUEL OIL	DIESEL FUEL OIL	MOTOR GASOLINE	L.P.G.	AVIATION GASOLINE	AVIATION TURBO	ELECT.	TOTAL REQTS
1978	.000	7.778	40.925	139.678	.000	1.518	19.258	.180	209.337
1979	.000	9.872	49.648	145.718	.603	1.619	23.168	.180	230.808
1980	.000	19.509	55.442	152.137	.546	1.549	24.679	.173	254.035
1981	.000	30.426	53.560	152.005	.421	1.361	24.352	.176	262.301
1982	.020	24.110	48.330	139.848	.829	1.001	19.648	.180	233.966
1983	.075	8.979	47.952	136.664	1.279	1.084	18.833	.180	215.046
1984	.149	4.075	49.356	133.478	1.310	1.208	18.963	.279	208.818
1985	.264	5.388	51.311	129.688	1.365	1.301	19.114	.310	208.741
1986	.674	16.900	52.375	126.038	1.462	1.332	22.102	.474	221.357
1987	1.455	17.792	53.432	122.991	1.573	1.332	21.538	.474	220.587
1988	2.269	18.953	55.007	120.422	1.721	1.332	21.035	.474	221.213
1989	3.086	19.832	55.975	118.167	1.903	1.332	20.479	.483	221.257
1990	3.385	20.370	56.923	116.157	2.147	1.332	19.929	.507	220.750
1991	3.733	21.103	58.804	115.015	2.463	1.332	19.507	.509	222.466
1992	4.114	21.945	61.142	114.656	2.799	1.332	19.157	.512	225.657
1993	4.532	22.678	63.321	115.032	3.153	1.332	19.859	.515	230.422
1994	4.983	23.357	65.183	116.052	3.517	1.332	20.557	.517	235.498
1995	5.463	24.071	66.918	117.627	3.887	1.332	21.225	.520	241.043
1996	5.969	24.781	68.453	119.631	4.255	1.332	21.918	.523	246.862
1997	6.496	25.528	69.729	121.968	4.615	1.332	22.543	.572	252.783
1998	7.043	26.315	71.032	124.633	4.965	1.332	23.108	.576	259.004
1999	7.611	27.129	72.333	127.575	5.303	1.332	23.716	.579	265.578
2000	8.191	27.956	73.587	130.749	5.625	1.332	24.312	.583	272.335
				ANNUAL GROWTH RATES					
1981-1990	.00	¯4.36	.68	¯2.94	19.84	¯.24	¯2.20	12.47	¯1.90
1990-2000	9.24	3.22	2.60	1.19	10.11	.00	2.01	1.41	2.12
1981-2000	.00	¯.44	1.69	¯.79	14.62	¯.11	¯.01	6.51	.20

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

Heavy fuel oil requirements for marine bunkering are forecast to decline from 1980 levels when special circumstances led to record high sales, and to resume growing by 1986 because of an improved competitive position.

Diesel requirements are anticipated to grow by an average annual rate of 1.7 percent between 1981 and the year 2000, reflecting continued growth in automotive and trucking, rail and coastal shipping requirements.

Aviation turbine fuel requirements have declined from the 1980 value of 24.7 PJ in the face of dramatic price increases and reduced traffic because of the slow economy. However requirements are expected to increase with the influx of tourists for Expo 86. By the end of the century requirements will almost reach their 1981 levels.

6.1 Road Sector

6.1.1 Introduction

Requirements in this sector encompass motor gasoline, diesel fuel, propane, compressed natural gas and electricity used for motive purposes in the operation of private and commercial on-road vehicles. Vehicles include automobiles, light, medium and heavy weight trucks and buses licenced to operate on public roads in the Province. Farm vehicles are also included. Electricity requirements are determined by electric trolley buses in Vancouver and the ALRT.

Section 6.1.2 provides a brief perspective of energy consumption in the historical period and Section 6.1.3 outlines the forecast. This latter section is divided into four separate subsections which discuss requirements for the sector as a whole, those for private vehicles followed by those for commercial vehicles. Lastly, electricity requirements are discussed.

6.1.2 Historical Profile

During the sixties and seventies, motor gasoline requirements rose quite dramatically at an average annual rate of 5.8 percent from about 52 PJ in 1961 to 152 PJ by 1980 (see Table 6.1.1). In part, this reflected growth in the stock of passenger vehicles through the second car phenomenon as the proportion of new smaller cars in total new car sales rose from 18 percent in 1965 to 33 percent by 1980. Indeed the number of passenger vehicles per person rose from 0.32 in 1966 to about 0.45 by 1980.

Total motor gasoline requirements peaked in 1980 but have since declined in the aftermath of the 30 percent increase in the real price of motor gasoline. This trend has been recently reinforced by the dramatic slowdown in economic activity in 1982. Requirements fell to 139.8 PJ in 1982 for an 8.1 percent drop over 1980. In light of the rapid increase in motor gasoline prices, the trend to smaller more fuel efficient cars has been intensified and they are estimated to have accounted for about 43 percent of total new car sales in British Columbia in 1982.

Through the historical period diesel fuel was used mainly by heavy weight trucks and buses. Since the first oil crisis in 1973, however, there has been an increasing trend toward diesel powered automobiles and light trucks. Diesel fuel

TABLE 6.1.1

HISTORICAL ROAD SECTOR ENERGY REQUIREMENTS

(PETAJOULES)

YEAR	MOTOR GASOLINE	DIESEL FUEL OIL	L,P,G,	TOTAL REQTS
1961	52.247	3.284	.000	55.531
1962	55.261	3.099	.000	58.360
1963	58.201	2.618	.000	60.819
1964	64.094	2.492	.000	66.586
1965	68.861	3.230	.000	72.091
1966	73.924	4.673	.000	78.597
1967	77.734	4.292	.000	82.026
1968	82.487	5.538	.000	88.025
1969	87.999	5.707	.000	93.705
1970	92.630	5.733	.000	98.363
1971	99.199	7.165	.000	106.364
1972	106.658	7.343	.000	114.001
1973	115.552	10.728	.000	126.280
1974	123.125	13.191	.000	136.315
1975	125.066	13.039	.000	138.105
1976	126.361	15.359	.000	141.721
1977	133.387	19.710	.000	153.097
1978	139.678	20.385	.000	160.063
1979	145.718	25.788	.603	172.110
1980	152.137	29.884	.546	182.567
1981	152.005	28.697	.421	181.123

ANNUAL GROWTH RATES

1961-1971	6.62	8.11	.00	6.72
1971-1981	4.36	14.88	.00	5.47

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

requirements grew dramatically over the previous two decades averaging about 11.4 percent annually from 3.3 PJ in 1961 to about 28.7 PJ in 1981. More recently, diesel requirements have declined from their peak values in 1980, reflecting for the most part, rising real diesel prices, particularly in the 1979 to 1982 period, and the slowdown in economic activity.

While propane has been used to power vehicles in the Province for quite some time (for example Johnstone Terminals have used propane powered vehicles since the early seventies) it has only been recently (since 1979) that measurable quantities of propane have been reported by Statistics Canada. Use of natural gas for vehicles (NGV - or compressed natural gas) is still in its infancy. In 1979 for example, only two vehicles were known to be powered by natural gas. This grew to approximately 147 vehicles by 1982, but requirements are still very small.

6.1.3 Forecast Period Assumptions

The requirements forecast presented here has been based on the Ministry's Energy Forecasting and Planning Model. This model was used to estimate requirements for the more traditional fuels, motor gasoline and diesel fuel by private and commercial vehicle types.

In developing the requirements forecast, factors such as fuel efficiencies, fuel prices, new car sales and vehicle stocks were taken into account. In the case of private passenger vehicles, new car sales were based on real disposable income per capita, and the price of new cars. New car sales were divided into small and large cars on the basis of relative fuel efficiencies for each category. The efficiency of the entire stock of passenger cars was then calculated by a vintaging process. Annual requirements were calculated by using the estimated fuel efficiencies and the number of kilometres travelled in one year.

Commercial vehicle stocks which include autos, light, medium and heavy trucks and buses are not determined in the same way as those of private vehicles in that they are not vintaged. Rather the stocks are related to GDP. Other factors, such as fuel efficiencies and the number of kilometers driven have been treated in a similar manner to those underlying private vehicles' requirements.

Propane and NGV requirements are determined by vehicle type: small and large passenger vehicles, personal use trucks and vans, commercial automobiles, light and medium trucks. For the passenger vehicle categories, propane, compressed natural gas and diesel vehicles are shared out from what would otherwise have been gasoline vehicles.

Discussion of the road forecast begins with assumptions regarding factors common to both private and commercial vehicle requirements, such as fuel prices and fuel efficiencies. This is followed by four sections which report total, private vehicle, commercial vehicle and urban transit requirements separately.

6.1.3.1 Fuel Prices

Based on the expected increase in world oil and domestic refinery gate crude prices, as outlined in Chapter 2 and the current structure of provincial taxes on gasoline, motor gasoline prices are anticipated to remain virtually constant in real terms over the period 1982 to the year 2000. This is in contrast to the experience in the 1979 to 1982 period when real motor gasoline prices increased at an average annual rate of 8.6 percent.

While diesel prices increased at a faster rate than other refined petroleum product (RPP) prices between 1980 and 1982, they are anticipated to follow those of gasoline over the forecast period.

Retail prices for alternative fuels were estimated on the basis of those which existed in 1983. At that time the retail price of propane was in the range of 18 - 20¢/litre (as reported by Energy Pricing News, May 1983 for Vancouver) whereas in June, 1983 the retail price of NGV, which is not normally measured in litres, was about 22¢/litre equivalent at retail pumps in Vancouver.[1]

Over the forecast period, the retail price of NGV, excluding an estimated dealer margin, was tied to the Ministry's forecast of the commercial sector price of natural gas. The dealer margin was then held fixed in real terms. Propane prices, on the other hand, were tied to the world price of oil on the basis of industry information which indicated that propane prices were largely determined by heating oil prices in the U.S. Given that U.S. oil prices are unregulated, they should closely track those in international markets.

---

[1] A litre equivalent (.58 kg) is the amount of natural gas required by an automobile to travel the same distance as it would travel using one litre of gasoline. Thus this takes into account the efficiency improvement which on-road experience suggests is around 10 percent.

6.1.3.2 Fuel Efficiency Forecast

Through to the 1986 period, large and small passenger vehicles have been assumed to become more fuel efficient as scheduled by the Corporate Average Fuel Efficiency standards of the Government of Canada. Based on announcements by the major auto producers and estimates made by the National Energy Board, fuel efficiency ratings are anticipated to improve through to 1990 after which no appreciable improvements are expected. (See Table 6.1.2)

Table 6.1.2

Fuel Efficiencies for New Passenger Vehicles*

(Litres/100 Kilometers)

	Small Cars	Large Cars
1978	10.8	14.9
1979	10.2	14.6
1980	9.8	13.6
1986	7.0	10.2
1990	6.4	9.4
2000	6.4	9.4

---

* These include a 15% degradation factor reflecting actual on-road experience as estimated by W.A. Niskansen, Chief Economist, Ford Motor Company, 1980. Source: National Energy Board, Ottawa.

6.1.4 Total Energy and Fuel Requirements Forecast

6.1.4.1 Total Road Requirements

It is anticipated that weak economic growth along with a trend toward smaller more fuel efficient cars, in response to the large increases in real gasoline prices over the 1979 to 1982 period, will combine to reduce motor gasoline requirements through to the early nineties. By 1990, most of the potential improvements in fuel efficiencies will have been exploited so that growth in the stock of vehicles - particularly commercial vehicles - will lead to an increase in motor gasoline requirements.

Throughout the forecast period, it is anticipated that motor gasoline requirements will be displaced by relatively less expensive alternative fuels such as propane, compressed natural gas and diesel fuel. Payback period analysis suggests that the greatest potential for motor gasoline displacement is centered with commercial vehicles. By the year 2000 alternative fuels make up 3.5 percent of non-diesel requirements for passenger vehicles compared to 25 percent for commercial vehicles.

An annual summary of the complete road forecast is presented in Table 6.1.3, where motor gasoline requirements are shown to fall from 152.0 PJ in 1981 to 130.7 PJ in 2000. Propane plus NGV requirements increase from 0.42 PJ in 1981 to 12.0 PJ by 2000. It is anticipated that total requirements for the road sector including truck diesel fuel will first decline and then almost attain the 1981 values at the end of the century. The positive requirements growth is, however, centered primarily in the 1990's where higher rates of economic growth lead to an increase in the demand for trucks

TABLE 6.1.3

ROAD TRANSPORT SECTOR
ENERGY REQUIREMENTS

(PETAJOULES)

YEAR	NATURAL GAS	DIESEL FUEL OIL	MOTOR GASOLINE	L,P,G,	ELECT,	TOTAL REQTS
1978	.000	20.385	139.678	.000	.180	160.243
1979	.000	25.789	145.718	.603	.180	172.290
1980	.000	29.884	152.137	.546	.180	182.740
1981	.000	28.697	152.005	.421	.173	181.299
1982	.020	25.997	139.848	.829	.176	166.874
1983	.075	25.092	136.664	1.279	.180	163.290
1984	.149	24.731	133.478	1.310	.180	159.848
1985	.264	24.227	129.688	1.365	.180	155.724
1986	.500	24.170	126.038	1.462	.180	152.500
1987	.753	24.270	122.991	1.573	.330	149.917
1988	1.022	24.631	120.422	1.721	.330	148.126
1989	1.311	25.212	118.167	1.903	.330	146.923
1990	1.610	25.705	116.157	2.147	.330	145.945
1991	1.958	26.640	115.015	2.463	.326	146.402
1992	2.339	27.627	114.656	2.799	.326	147.747
1993	2.757	28.666	115.032	3.153	.326	149.934
1994	3.208	29.719	116.052	3.517	.326	152.822
1995	3.688	30.749	117.627	3.887	.326	156.277
1996	4.194	31.780	119.631	4.255	.326	160.186
1997	4.721	32.799	121.968	4.615	.326	164.429
1998	5.268	33.791	124.633	4.965	.326	168.983
1999	5.836	34.805	127.575	5.303	.326	173.845
2000	6.416	35.788	130.749	5.625	.326	178.904

ANNUAL GROWTH RATES

1981-1990	.00	¯1.22	¯2.94	19.84	7.09	¯2.38
1990-2000	14.83	3.36	1.19	10.11	.00	2.06
1981-2000	.00	1.17	¯.79	14.62	3.30	¯.07

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

and automobiles. About 57 percent of the recovery in total requirements between 1990 and the year 2000 is accounted for by the growth in requirements for commercial vehicles.

6.1.4.2 Passenger Vehicle Requirements Forecast

Vehicle Stock Forecast

Central to the forecast of motor vehicle requirements is a forecast of the stock of motor vehicles. This depends upon, among other factors, new car sales. New car sales are a function of normalized real disposable income per capita, and passenger vehicle prices.

It is anticipated that real disposable income per capita will grow at an average annual rate of 1.3 percent between 1981 and the year 2000. Further, it was assumed the price of new cars will grow at the same rate as general inflation. Despite recent real price increases, future productivity gains through the employment of robot technology coupled with increasing worldwide competition should work to keep auto price increases to a minimum. It is interesting to note that Transport Canada[2] has assumed that auto prices would increase at a rate 1 percent below inflation to 1985 but equal to inflation from 1985 to 1990.

New car sales have also been adjusted so as to reflect observed trends in the U.S.. Table 6.1.4 indicates that the stock of passenger vehicles per household or per person is anticipated to continue increasing through the forecast period with new car sales increasing at an average annual

---

[2] "Transportation Demand and Oil Use to 1990", Transport Canada, February 1982.

Table 6.1.4

A Comparison of Forecasts of the Number of Automobiles per Person and per Household (British Columbia)

	Automobiles per Household			Automobiles per Person	
	MEMPR80+	Resourcecon*	MEMPR84	Resourcecon*	MEMPR84
1970	1.18	-	1.18	-	0.35
1980	1.15	1.22	1.21	0.46	0.44
1991	1.30	1.24	1.22	0.52	0.46
1996	1.37	1.24	1.29	-	0.51
2000	-	-	1.36	0.54	0.56

+ "British Columbia Energy Supply and Requirements Forecast 1979-1996." Ministry of Energy, Mines and Petroleum Resources, January 1980. Estimates were made on the basis of the study by D. Sharp; "Projections of Automobile Ownership and Use Based on Lifestyle Factors", Oak Ridge National Laboratory, March 1979, and approximates trends in the United States.

* "CNG Market Forecast: B.C. Hydro Gas Service Area, 1981 to 1990", Canadian Resourcecon, December 1981. Submitted to the Govier Inquiry on British Columbia's Requirements, Supply and Surplus of Natural Gas and Natural Gas Liquids. Estimates are for the Lower Mainland.

Table 6.1.5

New Car Sales and the Stock of Passenger Vehicles (British Columbia)

	Sales (000)	Stock (000)
1981	101.557	1,189.9
1985	104.343	1,286.7
1990	125.875	1,456.6
1995	155.077	1,698.1
2000	189.764	2,050.5
AAR 1981-1990	2.4	2.3
AAR 1990-2000	4.2	3.5
AAR 1981-2000	3.3	2.9

rate of 3.3 percent between 1981 and the year 2000. In the period 1990 through to 2000, on the other hand, new car sales surge to an average annual rate of 4.2 percent (see Table 6.1.5) as real income per person increases more rapidly.

Underlying the growth in the stock of motor vehicles each year is the combined but offsetting forces of additions to the stock through new car sales and depletions as the existing stock is retired. Based on a survival curve technique, it was estimated that, after accounting for the infusion of out of province vehicles, B.C. vehicles lasted a maximum of twenty years and one half of the cars sold in a given year lasted 12.8 years.[3] Together, new car sales, as outlined in Table 6.1.5, and the vintaging process result in the passenger vehicle stock increasing at an average annual rate of 2.9 percent between 1981 and 2000.

Improving relative fuel efficiencies and growing real income per person also combine to increase the proportion of smaller more fuel efficient cars to about 69 percent of new passenger vehicle sales by the year 2000. Smaller cars make up more than half of the 2 million passenger vehicles in the year 2000.

---

[3] The NEB estimated a maximum car life of 28 years and a half life of 18 years for British Columbia. See Shalaby A.S. and Waghmere R.R. "A Model for Forecasting Passenger Car Gasoline Demand" "Energy Policy Modeling: United States and Canadian Experiences," W.T. Ziemba et al; Volume 1, Martimus Nijhoff Publishing, 1980.

Fuel Requirements Forecast

In light of the trends in the composition of passenger vehicle stocks, improvements in the fuel efficiency ratings and growth in the total passenger vehicle stock, total fuel requirements for passenger vehicles are anticipated to decline from 127.9 PJ in 1981 to 114.2 PJ by the year 2000 with motor gasoline requirements falling from 127.8 PJ in 1981 to 107.4 PJ by 2000 (Table 6.1.6). In the 1981 to 1990 period, the total requirements decline reflects improvements in fuel efficiencies combined with a swing to more fuel efficient vehicles. By 1993, total fuel requirements start to increase, reflecting the growth in vehicle stock brought on by improved economic growth and the absence of further improvements to fuel efficiencies.

The forecast of fuel requirements for passenger vehicles also includes alternative fuels to gasoline: diesel fuel, propane and natural gas. The limitation of our forecast of "exotic" fuels to propane and natural gas is based, for the most part, upon the analysis presented in a study by Canadian Resourcecon.[4] After taking into account the economics and physical characteristics of compressed natural gas, liquefied natural gas, propane, alcohol-gasoline blends, and straight-alcohol fuels, propane and compressed natural gas emerged as the most economic alternatives.

---

[4] "Alternative Fuels for Automotive Vehicles in British Columbia", Canadian Resourcecon, March 1981. As well, see "Alternative Transportation Fuels in Canada", Canadian Energy Research Institute, July 1982.

TABLE 6.1.6

PASSENGER VEHICLES
ENERGY REQUIREMENTS

(PETAJOULES)

YEAR	NATURAL GAS	DIESEL FUEL OIL	MOTOR GASOLINE	L.P.G.	TOTAL REQTS
1978	.000	.000	115.329	.000	115.329
1979	.000	.017	120.118	.000	120.135
1980	.000	.043	127.430	.000	127.473
1981	.000	.087	127.797	.000	127.884
1982	.000	.150	119.375	.011	119.536
1983	.001	.252	117.043	.017	117.313
1984	.004	.372	114.296	.039	114.711
1985	.022	.579	111.089	.097	111.787
1986	.042	.780	107.818	.178	108.818
1987	.069	.974	104.994	.263	106.300
1988	.104	1.161	102.421	.370	104.056
1989	.144	1.340	99.978	.497	101.959
1990	.191	1.508	97.836	.689	100.224
1991	.252	1.672	96.278	.891	99.093
1992	.327	1.830	95.447	1.106	98.710
1993	.417	1.982	95.299	1.328	99.026
1994	.519	2.124	95.772	1.554	99.969
1995	.633	2.256	96.816	1.780	101.485
1996	.755	2.378	98.290	2.000	103.423
1997	.882	2.492	100.108	2.206	105.688
1998	1.011	2.595	102.272	2.398	108.276
1999	1.141	2.695	104.704	2.572	111.112
2000	1.270	2.792	107.396	2.728	114.186
ANNUAL GROWTH RATES					
1981-1990	.00	37.29	¯2.92	.00	¯2.67
1990-2000	20.86	6.35	.94	14.75	1.31
1981-2000	.00	20.03	¯.91	.00	¯.59

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

It must be recognized however, that natural gas and propane are both hydrocarbons with finite long-term supplies. As the availability of these fossil fuels decreases over time, rising prices will encourage the development of lower cost alternatives such as hydrogen. At this time, however, the phase-in of non-fossil based fuels is still highly speculative. Consequently the forecast of motive fuel requirements presented here excludes the non-fossil based alternatives which are, in any event, likely to be more important at some time in the next century.

Among the major factors underlying the decision to convert to propane or NGV are the net conversion costs (that is, conversion costs less subsidies), the price of the alternative fuel relative to that of gasoline and the volume of fuel used over a given period (e.g. a year). Estimates by Canadian Resourcecon and CERI[5] put costs for propane conversions in the range of $1000 - $1800 depending on the type of vehicle and equipment installed with the largest proportion of cost being made up by the fuel tank. A small car with a correspondingly smaller fuel tank would fall in the lower end of the range.

Due to the higher pressures for natural gas (in the range of 2400 - 3000 psi compared to 120 - 160 psi for propane), fuel tanks must be built with more integrity, utilizing high strength steel. This pushes conversion costs for NGV higher than for propane and into the $1500 - $2000 range. Again a smaller car with a smaller tank would fall in the lower end of the range.

---

[5] "Alternative Transportation Fuels in Canada" Canadian Energy Research Institute (CERI), C. Slagorsky Calgary, Study No. 16, July 1982.

Currently both the federal and the provincial governments offer incentives to partially offset these initial costs. The federal government has established a taxable grant of $400 to offset initial conversion costs for propane conversions and a taxable grant of $600 for compressed natural gas conversions in either commercial or non-commercial vehicles.

The Government of British Columbia has also established a taxable grant of $200 for natural gas conversions in addition to those offered by the federal government. The Province has also exempted both propane and natural gas from road taxes. Conversion kits for propane and NGV have been exempted from retail sales taxes as well.

In addition to the incentives announced by both the provincial and federal governments, B.C. Hydro has established a program for conversions to natural gas within its own gas distribution area. B.C. Hydro will provide an interest free loan of $500 with up to 24 month repayment terms. This is in addition to a fleet owner plan whereby NGV fleet owners can finance vehicle conversions and refueling equipment with no down payment and up to a 5 year repayment at very low interest rates.

The on road experience with alternative fuels as reported by the Ontario Ministry of Transportation and Communications propane demonstration program indicates that it takes approximately 1.2 litres of propane to travel the same distance as one litre of gasoline. After allowing for this adjustment, the current price of propane per litre equivalent is 24¢. Thus, both propane and NGV are about half the price of regular unleaded motor gasoline which in April 1984 was in the order of 49¢/litre at self-service stations in Vancouver. This relationship has been assumed to continue through the forecast period.

For illustration purposes, estimates of possible pay-back periods have been prepared for private passenger vehicles assumed to travel the average of 18,980 kilometres (11,796 miles) per year in B.C. as determined by Statistics Canada. These estimates are reported for three different efficiency ratings, typical of recent model automobiles. For example, the Mazda GLC has a fuel efficiency rating in the area of 6 litres/100 km whereas a Cadillac is typically closer to 19 litres/100 km. Mid-sized cars, such as the Ford Granada, are closer to 10 litres/100 km.

Table 6.1.7 summarizes the results. Estimates of pay-back periods for propane and NGV conversions with and without government assistance are reported so as to indicate the impact of the assistance. It is clear that without such assistance, propane would enjoy a shorter pay-back period in all cases but particularily for the more fuel efficient automobiles. However, with the available subsidies, the pay-back period is slightly shorter for NGV than for propane for the larger private passenger vehicles. No analysis has been conducted to determine what impact B.C. Hydro's incentives would have since the illustration in Table 6.1.7 is for a simple payback period. However, if discounting were applied NGV would enjoy payback periods similar to those in Table 6.1.7 where as the payback period for propane would be longer. The results of Table 6.1.7 also indicate that only vehicles with annual requirements in excess of 3600 litres will achieve pay-back periods under two years.

Despite a slightly more favourable payback period, NGV has some non-economic disadvantages relative to propane. The vehicle range is typically less for natural gas than for propane due to the lower volume of fuel which can be stored

Table 6.1.7

Range of Possible Payback Periods for Private New Passenger Vehicles*

Fuel Efficiency	Annual** Fuel Req.	Conversion Cost Assumpt.		Payback Period in Years			
				Without Subsidy***		With Subsidy+	
(litre/100km)	(litres)	Propane	NGV	Propane	NGV	Propane	NGV
6.0	1139	$1000	$1500	3.3	4.6	2.4	2.9
10.0	1898	$1500	$1700	3.2	3.4	2.6	2.3
19.0	3606	$1800	$2000	2.1	2.2	1.8	1.6

---

* Discounting has not been taken into account. This would have the effect of making the payback period longer.

** It has been assumed that the vehicle travels 18,980 km per year. This understates the payback period for smaller cars given that estimates by the NEB indicated they are typically driven fewer kilometers per year.

*** It has been assumed that the fuel savings for propane are 22¢/L and 24¢/L for natural gas. As well, maintenance cost savings of $50 per year for both types of conversion have been assumed. In addition, significant savings also occur because the use of natural gas or propane has been estimated to extend the engine life by at least 50 to 100 percent over gasoline use. This however, was not factored into analysis above.

+ A personal income tax rate of 30 percent was used.

in a given space. This gives rise to more frequent fill-ups. Further, NGV, because of its greater space requirements for a given range, leaves less storage space for other articles. While it is difficult to estimate the dollar value these inconveniences place on a consumer, they are nevertheless factors which must be taken into account in estimating the relative acceptance for each fuel.

While the above analysis indicates considerable cost savings are available to the consumer from switching to either propane or natural gas, additional factors weigh heavily in the decision to convert. Important among these are the availability of fuel, the high initial capital costs and uncertainty with respect to price and government taxation policy.[6]

With these broad concerns aside, it has been assumed that smaller cars will not convert to either propane or natural gas in light of their already high fuel efficiencies and consequently longer payback periods. Further, loss of space with added fuel tanks will be relatively more important to most small car owners and thus factor against conversion.

For larger passenger vehicles, it has been assumed that range and storage considerations put propane and CNG on equal footing, but with the 5700 propane vehicles currently in the Province and a propane distribution system already fairly well developed, higher capture rates for propane are expected to continue into the future as well. Thus by the year 2000, it is anticipated that the number of private vehicles using propane will be about 3.4 percent of the stock of larger cars whereas natural gas will account for about 2.1 percent as reported in Table 6.1.8.

---

[6] Barriers exist on the supply side as well. Suppliers who are uncertain about public acceptance of NGV will be unwilling to incur the high capital costs of installing natural gas refueling facilities, although a taxable federal grant of $50,000 is available to assist in offsetting these costs. The problem is not so severe with propane given that there are already over 350 propane outlets in the Province, including many existing service stations.

In light of the above assumptions, propane requirements are anticipated to reach 2.7 PJ for passenger vehicles by the year 2000. Table 6.1.6 also indicates that NGV requirements amount to only 1.3 PJ at the end of the forecast period. Together, propane and NGV amount to 3.6 percent of non-diesel requirements.

Some allowance has also been made for diesel fueled engines in the large and small passenger vehicle category. Up until 1981, most diesel powered passenger vehicles were imports from Europe (e.g. Rabbit, Mercedes, Peugeot) where higher world oil prices had prevailed for a long time. Not until recently did North American producers introduce diesel models. Diesel fuel, on the other hand, has lost some of its attractiveness vis-a-vis gasoline in the recent period with its price rising to almost the same level as gasoline.

It has therefore been assumed, that while diesel will continue to be attractive given its higher efficiency, it will not reach the capture rates assumed in earlier Ministry forecasts supplying only 2.8 PJ by the year 2000. Further, due to motor performance characteristics and price of diesel fuel compared to those of either propane or natural gas, it is anticipated that both propane and NGV will capture some of the market that would have otherwise used diesel. This was based, in part, on experience in Ontario where capture rates for propane have already outstripped that experienced for diesel.

Table 6.1.8

Proportion of Vehicles Using Propane or Natural Gas in the year 2000.*

	Capture Rate (percent) NGV	Propane
Private:		
-Large Auto	2.1	3.4
Commercial:		
- Auto	5.6	2.3
- Light/Medium Trucks	9.0	3.4

---

* These assumptions would encompass factory offered propane or NGV options. It has been assumed that producers will price the option to try to capture some of the rent accruing to the vehicle owner so that payback periods for the factory installed option will not differ appreciably from that of private conversions.

6.1.4.3 Commercial Vehicles Requirements Forecast

Commercial vehicles are defined to include automobiles, light and medium weight trucks (3,200 to 11,800 KG) and heavy weight trucks (11,800+ KG). These definitions correspond closely to those used by Canadian Resourcecon in the study referenced earlier. According to the 1980 motor vehicle statistics, there were approximately 85,177 commercial automobiles, 84,836 light and medium weight trucks and 24,529 heavy weight trucks in the Province. For the purpose of this forecast, it has been assumed that only diesel fuel is used in heavy weight trucks.

The stock of commercial vehicles is linked to total gross domestic product (GDP) on the basis of the relationship reported in the Ministry's 1981 forecast. As well, commercial automobiles are assumed to be driven approximately 50 miles a day or 29,364 km a year which again corresponds closely to the assumption adopted by Canadian Resourcecon. Their fuel efficiencies were estimated as the average of the most recent four years of fuel efficiencies for larger passenger vehicles. Consequently, they improve until 1994 after which they remain constant,

In the commercial light and medium truck category, an average fuel efficiency of 30.2 litres/100 KM, (a figure which was reported in the Ontario Government propane fleet demonsatration program), was adopted. It was assumed that fuel efficiencies for light and medium trucks would improve at the same rate as fuel efficiencies for larger passenger vehicles. As well, these trucks are assumed to travel 110 miles per day or 40,000 miles/year (64,360 km/year). This was a figure quoted in the Ontario propane study and is slightly above the 105 miles/day used by Resourcecon.

In the case of heavy weight trucks, which are assumed to consume only diesel fuel, the average diesel requirement per truck for 1980 was estimated. This average was taken to be the product of the average number of kilometres driven per year per truck and the average fuel requirement in litres per kilometre. It has been assumed (as in the Ministry's 1981 forecast) that fuel efficiencies gradually improve by 20 percent over their 1980 values through the forecast period and that average distances travelled remain constant.

Given the GDP forecast, reported in chapter two, the above assumptions imply that total non-diesel fuel requirements for commercial automobiles, light and medium weight trucks, will increase from 24.8 PJ in 1981 to approximately 31.7 PJ by the year 2000 (Table 6.1.9).

Between 1981 and 1985, the decline in total requirements reflects improving fuel efficiencies combined with the downturn in economic activity and a recovery that does not attain 1981 levels until 1984. Requirements pick up beyond 1985 as the economy improves although 1980 demand levels are not anticipated to be achieved until the mid 1990's.

From 1990 through to the year 2000 total requirements are expected to grow on average by 3.5 percent annually. This growth is broadly based across all fuels and reflects primarily an upswing in economic activity. Diesel fuel for large trucks is anticipated to increase by 3.2 percent annually and reach 33.0 PJ by the year 2000. While growth in motor gasoline requirements is also strong there is some displacement with the increasing shares for propane and natural gas.

TABLE 6.1.9

COMMERCIAL VEHICLES
ENERGY REQUIREMENTS

(PETAJOULES)

YEAR	NATURAL GAS	DIESEL FUEL OIL	MOTOR GASOLINE	L.P.G.	ELECT.	TOTAL REQTS
1978	.000	20.385	24.349	.000	.180	44.914
1979	.000	25.772	25.600	.603	.180	52.155
1980	.000	29.841	24.707	.546	.173	55.267
1981	.000	28.610	24.208	.421	.176	53.415
1982	.020	25.847	20.473	.818	.180	47.338
1983	.074	24.840	19.621	1.262	.180	45.977
1984	.145	24.359	19.182	1.271	.180	45.137
1985	.242	23.648	18.599	1.268	.180	43.937
1986	.458	23.390	18.220	1.284	.330	43.682
1987	.684	23.296	17.998	1.310	.330	43.618
1988	.918	23.470	18.001	1.351	.330	44.070
1989	1.167	23.872	18.189	1.406	.330	44.964
1990	1.419	24.197	18.320	1.458	.326	45.720
1991	1.706	24.968	18.737	1.572	.326	47.309
1992	2.012	25.797	19.210	1.693	.326	49.038
1993	2.340	26.684	19.733	1.825	.326	50.908
1994	2.689	27.595	20.280	1.963	.326	52.853
1995	3.055	28.493	20.811	2.107	.326	54.792
1996	3.439	29.402	21.341	2.255	.326	56.763
1997	3.839	30.307	21.861	2.409	.326	58.742
1998	4.257	31.196	22.361	2.567	.326	60.707
1999	4.695	32.110	22.871	2.731	.326	62.733
2000	5.146	32.996	23.353	2.897	.326	64.718
			ANNUAL GROWTH RATES			
1981-1990	.00	¯1.84	¯3.05	14.80	7.09	¯1.71
1990-2000	13.75	3.15	2.46	7.11	.00	3.54
1981-2000	.00	.75	¯.19	10.68	3.30	1.02

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

In developing a forecast of alternative fuel requirements, it has been assumed that the highest capture rates of all vehicles would be for commercial vehicles (excluding heavy weight trucks which are assumed to use only diesel fuel). In light of the above assumptions with respect to annual kilometres driven and fuel efficiencies, these vehicles would typically achieve payback periods in the 1 - 1 1/2 year range for either propane or natural gas. Further, it has been assumed that neither propane nor natural gas are appropriate substitutes in heavy weight trucks utilizing diesel fuel.

For the period to the early 1990's, it is anticipated that propane will enjoy higher capture rates based on its availability of supply. Eventually however, it is expected that service stations within the duty cycle range of most commercial vehicles - principally the lower mainland - will add natural gas dispensing facilities and that an increasing number of commercial vehicles will convert to natural gas. In time, natural gas conversions can be expected to surpass conversions to propane through encouragement from Government.

It is anticipated that propane requirements for commercial vehicles will reach almost 2.9 PJ by the year 2000, whereas natural gas requirements will amount to 5.1 PJ or 16.2 percent of the non-diesel requirements of commercial vehicles.

6.1.4.4 Urban Transit Requirements

A number of communities in British Columbia including Vancouver, Victoria, Nanaimo and Prince George operate their own Urban Transit Systems. These systems, except for Vancouver, rely solely on diesel buses and the appropriate fuel requirements are included with those of commercial vehicles. Part of the Vancouver bus fleet, on the other hand, includes electric trolley buses that provide inner city service. As well, an Automated Light Rapid Transit (ALRT) System is scheduled to begin operation in 1986.

In determining urban transit electricity requirements, the same methodology and assumptions as in the Ministry's 1981 forecast have been employed. An upward revision to requirements in earlier years has, however, been made to reflect actual usage in 1980 and 1981 as reported by Statistics Canada. Further, it is anticipated now that the ALRT system will require slightly more electricity than initially estimated and this has been revised from 0.07 PJ to 0.15 PJ through the forecast period.

Electricity requirements are anticipated to grow from almost 0.18 PJ in 1981 to about 0.33 PJ by the year 2000. This increase in requirements reflects extensions to existing lines on the trolley system and the addition of the ALRT. These requirements are reported on an annual basis in Table 6.1.9.

6.2 Rail Sector

6.2.1 Introduction

Energy consumption in this sector is for fuel used to transport bulk commodities to westcoast ports by the major railways: CP Rail, CN Rail and B.C. Rail.[7] Among the major commodities transported are grains, coal and lumber. Requirements are principally for diesel fuel[8] with electricity requirement forecast to begin in 1984

---

[7] There are other railways in the province such as B.C. Hydro's; however, requirements are small by comparison.

6.2.2 Historical Profile

A significant portion of diesel fuel required is actually purchased in Alberta and then transported to fuel depots in B.C. for the hauling of grain and other commodities across the Rockies. Statistics Canada reports rail requirements in B.C. as fuel purchased within the province only. In keeping with this convention, requirements reported here include only diesel fuel purchased in B.C.[9]

Through much of the early sixties, requirements (that is diesel fuel purchased in B.C.) remained relatively flat. With the emergence of the interior forest products industry in the latter sixties however, diesel requirements began to increase steadily. A further stimulus was brought about in the early seventies with the commencement of coal shipments from the south eastern portion of the province to the Roberts Bank terminal near Vancouver.

---

[8] Some light fuel oil is also used. This has been assumed to be for ancillary purposes and thus is included in the commercial sector. Heavy fuel oil such as used by the Royal Hudson, is included in the commercial sector as well.

[9] Requirements in the Ministry's 1981 forecast included purchases from Alberta. Statistics Canada counts these as Alberta requirements and not B.C.'s since the point of purchase is Alberta.

During the oil crisis of 1973/74, real diesel fuel prices increased dramatically and B.C. rail loadings slowed down. Consequently, requirements growth began to falter and declined through to 1976. Total fuel used in British Columbia, as indicated in Table 6.2.1, also declined. Some offset occurred with transfers from Alberta that were associated with grain, potash and sulphur shipments.

Table 6.2.1

Origin of Diesel Fuel
Used by Railways in
British Columbia
(petajoules)

	Diesel Fuel Purchased in B.C.	Diesel Fuel Purchased in Alberta	Total Diesel Fuel Used
1971	8.37	3.39	11.76
1972	9.73	3.53	13.26
1973	9.79	3.46	13.25
1974	9.73	3.22	12.95
1975	8.06	5.38	13.44
1976	7.26	5.16	12.42
1977	7.72	5.86	13.58
1978	8.83	6.28	15.11
1979	9.45	6.29	15.74

6.2.3 Forecast Period Assumptions

Energy requirements are derived in large part, from the transhipment of bulk commodities destined for export. In this forecast, energy requirements have been related to a shipments variable, which included the principal export commodities: the major grains, coal and lumber output from the interior of the province.

A grain export forecast, prepared by Transport Canada[10] was adopted for constructing the shipping variable. Grain exports were forecast to grow by 5.5 percent annually between 1981 and 1990. Beyond 1990, the period not covered by the Transport Canada forecast, the Ministry has assumed that grain exports will continue to grow at the same rate of 5.5 percent.

Coal exports are defined to include virtually all the coal produced in British Columbia plus Alberta coal exports destined for Pacific Rim countries. For the period prior to 1995, an Alberta coal export forecast was adopted.[11] Beyond 1995 however, it has been assumed that Alberta coal exports grow at the same rate as those from British Columbia. Together, B.C. production and Alberta exports amount to almost 52 million tonnes by 1990 and this estimate is in agreement with the forecast prepared by Transport Canada (referred to above). Between 1981 and the year 2000, it is anticipated that coal exports will grow at an average annual rate of 7.2 percent, with most of this growth centered in the late eighties.

Interior lumber production, which has been presented in more detail in sector 5.1.2, is expected to remain relatively constant over the forecast priod at approximately 7.4 million tonnes.

---

[10] "Transport Canada Freight and Passenger Forecasts," Transport Canada, December 1982.

[11] Alberta coal exports were determined on the basis of an unpublished forecast by the Alberta Energy Resources Conservation Board prepared in September 1982.

6.2.4 Total Energy and Fuels Requirements Forecast

Forecasts for both diesel fuel and electricity requirements have been prepared and are reported separately below.

6.2.4.1 Diesel Fuel

Diesel fuel requirements have been forecast by relating fuel consumption to rail shipments discussed earlier and also to the price of diesel fuel.[12] Over the period from 1981 to the year 2000, it has been assumed that real prices for non-road diesel fuel will increase by approximately 1.2 percent annually. With an estimated long run elasticity of 0.75, diesel fuel price increases alone would result in a reduction in requirement's growth by 0.9 percent annually.

Recently, requirements declined from their 1981 level of 10.9 PJ (Table 6.2.2) to 9.8 PJ by the end of 1983 reflecting, in part, the earlier real price increases of almost 63 percent between 1979 and 1982. However, requirements growth is expected to resume in 1984 as shipments growth begins to pick up.

For the remainder of the period 1984 through to the year 2000, real diesel prices are anticipated to increase only very slightly whereas rail shipments growth, particularly for coal at 4.7 percent per annum, continues to increase dramatically. Hence, between 1984 and the year 2000, diesel

---

[12] Refer to B.C. Energy Demand Forecasting and Planning Model: Staff Paper March 1983 for equation specification.

TABLE 6.2.2

RAIL TRANSPORT SECTOR
ENERGY REQUIREMENTS

(PETAJOULES)

YEAR	DIESEL FUEL OIL	ELECT,	TOTAL REQTS
1978	8.833	.000	8.833
1979	9.448	.000	9.448
1980	10.187	.000	10.187
1981	10.867	.000	10.867
1982	10.176	.000	10.176
1983	9.852	.000	9.852
1984	10.605	.099	10.704
1985	11.830	.130	11.960
1986	13.040	.144	13.184
1987	14.232	.144	14.376
1988	15.205	.144	15.349
1989	15.570	.153	15.723
1990	15.609	.181	15.790
1991	15.730	.183	15.913
1992	15.907	.186	16.093
1993	16.069	.189	16.258
1994	16.266	.191	16.457
1995	16.526	.194	16.720
1996	16.655	.197	16.852
1997	16.576	.246	16.822
1998	16.585	.250	16.835
1999	16.581	.253	16.834
2000	16.578	.257	16.835

ANNUAL GROWTH RATES

1981-1990	4.11	.00	4.24
1990-2000	.60	3.57	.64
1981-2000	2.25	.00	2.33

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

requirements grow at an average annual rate of 2.8 percent. However, requirements growth slows during the last decade of this period as coal exports grow at only 1.3 percent annually.

6.2.4.2 Electrification

In the Ministry's previous forecast, the opportunities and technical advantages of rail electrification were outlined in some detail. Specific advantages associated with high-volume tracks were identified, particularly in areas of steep grades. Interest has been expressed by CN and CP Rail in the possible electrification of a portion of their mainlines through the Rockies. Because of steeper gradients and more pressing capacity constraints, CP probably has the greater incentive for electrification.

The capital costs associated with electrification of existing lines are very high and such expenditures would have to compete for financing with other projects planned by the railways. Both major railways will face significant capacity constraints in Western Canada within a few years and these will require massive investments in double tracking, new tunnels, other line improvements and new rolling stock which will be financed only partly by the new Crow's Nest rates.

In light of the squeeze on financial resources expected by the railways, and the high real interest rates and high real electricity prices assumed by the Ministry, it has been assumed that electrification of CP or CN lines would not proceed over the next 15 years.

Recently, however, B.C. Rail opened a 130 km branch line from its main line at Anzac, near Prince George, to Tumbler Ridge, to haul coal from the northeast coal fields. Primarily because of the ventilation problems faced in the line's major tunnels, B.C. Rail decided to electrify the line using a high-voltage (50 kv) system.

Based on the Ministry's forecast of northeast coal production and estimates of electricity consumption per tonne of coal hauled, provided by B.C. Rail, it is estimated that electricity requirements would increase from almost 0.10 PJ in 1984 to 0.26 PJ by the year 2000.

6.3 Marine Sector

6.3.1 Introduction

The marine sector encompasses requirements for diesel and heavy fuel oil used in domestic and international shipping operations in the for-hire category. Domestic shipping includes marine carriers operated as subsidiaries of railway companies - e.g. C.P. Ferry operations.

In part of the historical period, requirements of government operated ferries such as those of the Ministry of Highways and the B.C. Ferry system may have been included in the commercial sector and not in the marine sector. As noted previously, information was too incomplete to separate these out. Excluded from the marine sector requirements are fuels used by vessels not in the for-hire category. For example, fuels used by vessels operated by oil or forest product companies have been included in the industrial sector.

6.3.2 Historical Profile

Requirements for diesel fuel are essentially determined by the coastal movement of goods, principally lumber. While these requirements have grown somewhat erratically over the historical period they have trended from 7.8 PJ in 1968 to almost 15.4 PJ by 1980.

Heavy fuel oil requirements, on the other hand, are related to the export of bulk commodities such as grains, pulp and lumber. Coal exports are less important in assessing marine fuel demand due to the tendency for carriers to double bunker. The flexibility to satisfy fuel requirements from other than B.C. sources has led to a very erratic sales history with demand escalating rapidly from 9.8 PJ in 1979 to 19.5 PJ in 1980 and 30.4 PJ in 1981 after which it dropped back to 24.1 PJ in 1982 and 8.9 PJ in 1983.

Since factors and issues defining the requirements for marine diesel and heavy fuel oil are distinctly different, the forecast for each fuel is discussed separately. In the historical period diesel fuel and heavy fuel oil were the only fuels used in the marine sector for motive purposes. Recently however, the B.C. Ferry Corporation announced plans to convert part of its fleet from diesel fuel to natural gas. Below, the discussion of these natural gas requirements is included with that of diesel fuel oil.

6.3.2 Total Energy and Fuels Requirements

6.3.2.1 Diesel Fuel and Natural Gas

The factors used in forecasting marine diesel requirements included coastal lumber production, and real disposable income per capita. This latter variable is intended to proxy for the general shipment of goods along the coast of British Columbia.

Coastal lumber production is forecast to almost reach 1979 levels by 1985 and with the exception of 1986 and 1987 grow modestly thereafter. More detail is provided in section 5.1.2 of chapter five. In the short term, it is anticipated that diesel requirements will recover quickly from the 1982 value of 12.2 PJ, reaching almost 15.3 PJ by 1985 (Table 6.3.1).

In 1986, the B.C. Ferry Corporation plans to convert one of its ships to run on a combination of diesel and natural gas. Initial plans call for a fuel mixture of 80 percent natural gas and 20 percent diesel fuel oil. By 1988, the corporation intends to have eight more ferries running on a combination of natural gas and diesel fuel. Based on information provided by the B.C. Ferry Corporation, the Ministry has estimated that by 1988 natural gas requirements could amount to as much as 1.8 PJ. Consequently, diesel requirements have been correspondingly reduced from what they otherwise would have been.

During the nineties, diesel requirements are forecast to increase at an average annual rate of about 3.1 percent, reflecting growth in non-lumber coastal shipment activity as measured by per capita real disposable income. Overall, requirements grow by an average annual rate of 2.2 percent reaching 21.2 PJ by the year 2000.

6.3.2.2 Heavy Fuel Oil

Heavy fuel oil used for marine bunker is consumed almost entirely by vessels engaged in the international shipment of bulk commodities such as grain, pulp and lumber. As already indicated vessels transporting coal have tended to double

TABLE 6.3.1
MARINE SECTOR
ENERGY REQUIREMENTS

(PETAJOULES)

YEAR	HEAVY FUEL OIL	DIESEL FUEL OIL	NATURAL GAS	TOTAL REQTS
1978	7.778	11.707	.000	19.485
1979	9.872	14.411	.000	24.283
1980	19.509	15.371	.000	34.880
1981	30.426	13.996	.000	44.422
1982	24.110	12.157	.000	36.267
1983	8.979	13.008	.000	21.987
1984	4.075	14.020	.000	18.095
1985	5.388	15.254	.000	20.642
1986	16.900	15.165	.174	32.239
1987	17.792	14.930	.702	33.424
1988	18.953	15.171	1.247	35.371
1989	19.832	15.193	1.775	36.800
1990	20.370	15.609	1.775	37.754
1991	21.103	16.434	1.775	39.312
1992	21.945	17.608	1.775	41.328
1993	22.678	18.586	1.775	43.039
1994	23.357	19.198	1.775	44.330
1995	24.071	19.643	1.775	45.489
1996	24.781	20.018	1.775	46.574
1997	25.528	20.354	1.775	47.657
1998	26.315	20.656	1.775	48.746
1999	27.129	20.947	1.775	49.851
2000	27.956	21.221	1.775	50.952

ANNUAL GROWTH RATES

1981-1990	¯4.36	1.22	.00	¯1.79
1990-2000	3.22	3.12	.00	3.04
1981-2000	¯.44	2.21	.00	.72

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

bunker (that is take on enough bunker for a return trip) or take on bunker elsewhere. Furthermore, vessels taking on cargo in Vancouver have the option of bunkering at other westcoast ports such as Port Angeles or Seattle. The decision to bunker in Vancouver is based both on the price of heavy fuel oil in Vancouver vis a vis other westcoast ports and the availability of fuel. Indeed, industry estimates that less than one third of the potential marine bunker sales were supplied in 1981 - a record year for sales in B.C..

The dramatic increase in the sale of heavy fuel oil during the 1979 to 1981 period was due not so much to a pickup in the growth of shipping demand as it was attributable to the diversion of marine fuellings to B.C. ports from U.S. facilities. This was brought about by the escalating price for heavy fuel oil along the westcoast relative to a more stable price in British Columbia. These increased sales were met primarily by transfers from Alberta where refineries have the option of shipping their product either to the westcoast or to Eastern Canada.

In order to compensate for the low Canadian crude price relative to world oil prices, the federal government instituted a Transportation Fuel Compensation Recovery Charge (TFCRC) in May of 1981. The province of B.C., as well, adopted an ad valorem tax based on the price of "clear gasoline".

In May of 1981, the sum of these two taxes totalled $10.11 (Canadian) per barrel, or about 28 percent of the Vancouver selling price. At this time, the price of bunkers in the international market was high enough to permit B.C. suppliers a satisfactory after-tax return. These taxes, along with the increasing costs of crude and a weakening market for international bunkers, combined to reduce after-tax returns.

As a consequence, Alberta suppliers diverted their product to the more attractive eastern markets and heavy fuel oil availability was reduced by 26 percent in 1982. As well, local output fell as declining demand for light oil products reduced the volume of crude oil processed and consequently the volume of heavy fuel oil produced as a by-product. Lower yields of heavy fuel oil were also realized by including additional light feedstocks such as synthetic crude and condensate to displace crude oil in refinery intake.

In developing a forecast of heavy fuel oil requirements, reliance has been placed mainly on those factors affecting demand in spite of the supply side considerations, as outlined above.[13] This approach was adopted because those elements affecting availability are less predictable. Cognizance has been taken, however, of the most likely supply side considerations.

In February 1983, the Federal Government eliminated the TFCRC. This was not anticipated to be of much relief to suppliers in light of the low international price for heavy fuel oil and the provincial tax which existed at that time.[14] However, U.S. westcoast supplies of heavy fuel oil are currently being targeted for Pacific Rim consumption, leaving little for marine bunkering. Consequently, there is a shortage of heavy fuel oil on the westcoast and prices are firming. This situation should improve the prospects for marine bunker sales in time, as supplies increase in response to higher prices.

---

[13] The equation relating heavy fuel oil requirements to exports and the price of heavy fuel oil in B.C. relative to the world level, is reported in the B.C. Energy Demand Forecasting and Planning Model document.

The demand for heavy fuel oil has been forecast as a function of the exports of grain, pulp and lumber, and the price of heavy fuel oil in B.C. relative to the international bunker price available on the U.S. westcoast. Both pulp, paper and lumber exports have been forecast to grow at the same rate as production of these commodities. A forecast of production levels can be found in sections 5.1.1 and 5.1.2 of chapter five. For grain exports, a forecast prepared by Transport Canada has been adopted. It will be recalled that grain exports are expected to grow by an average annual rate of 5.5 percent. The impact of fuel cost was included by assuming the price of heavy fuel oil would grow at the same rate as the world price of crude oil.

With due consideration to the factors outlined above, requirements for heavy fuel oil, as reported in Table 6.3.1, are expected to decline from 1981 levels. Preliminary estimates for 1984, indicate that the low volumes of throughput along with lower proportions of heavy fuel oil per barrel of feedstock will establish sales in the range of 4.0 PJ and increase only slightly in 1985.[15] Requirements in 1986 reflect the displacement of heavy fuel oil by natural gas service to pulp and paper mills on Vancouver island. Implicit, is the assumption that marine bunkering will provide sufficient netbacks to suppliers so as to absorb the displaced fuel.

---

[14] The method of calculating provincial tax was changed in the July 5th 1983 budget to an ad valorem tax based on the price of heavy fuel oil and came into effect in September, 1983. Based on the current price for heavy fuel oil, the provincial tax currently is about $6.11 per barrel.

Beyond 1990, requirements are assumed to be solely determined by demand side factors where it has also been assumed that transfers from Alberta will be available. During the nineties requirements grow at an average annual rate of 3.2 percent from 20.3 PJ in 1990 to 28 PJ by the year 2000 with some 33 percent or more met from extraprovincial sources.

6.4 Air Sector

6.4.1 Introduction

This sector is defined to include the requirements of aviation gasoline and aviation turbine (turbo) fuel used for the operation of domestic and international scheduled flights and general aviation in British Columbia.

6.4.2 Historical Profile

During the sixties aviation turbo fuel replaced aviation gasoline as the major fuel used in the aviation industry. With the growth in longer range flights and consequently the use of jets and turbo-prop airplanes, turbo fuel requirements jumped from 1.6 PJ in 1960 to about 24.6 PJ by 1980.

---

[15] Due to upgrading of catalytic crackers by refineries in B.C., the amount of heavy fuel oil as a percentage of B.C. refinery throughput on an energy basis is expected to decline from 11.3 percent in 1981 to 8.9 percent in 1990. However, it will gradually increase to 9.4 percent by the year 2000 with the heavier quality of crude.

Since 1980, however, turbo fuel requirements have declined in the face of rising real fuel prices. Fuel costs, as a proportion of total operating costs, rose from 19 percent in 1976 to 23 percent by 1980.[16] As a consequence, airlines realigned schedules, rationalized routes and began to phase-out fuel inefficient aircraft through either retrofitting or acquiring more fuel efficient jets.[17] More recently, weak economic performance worldwide has led to a decline in air traffic.[18] This has forced the airlines to reduce the number of flights and hence consume less fuel. This adjustment process is expected to continue for some time.

Also among the factors contributing to the decline from 1980 volumes, was the imposition of the federal Transportation Fuel Compensation Recovery Charge (TFCRC) which increased the cost of turbo fuel to near world levels, hence reducing the opportunity for foreign carriers to take on fuel at relatively cheap prices. This was removed early in 1982 in order to avoid contravening the International Air Transport Agreement (IATA) to which Canada is a signatory. In its place a minimum price for aviation turbo fuel was set. But by the spring of 1983, the enforcement of a minimum price was discontinued with the recent fall in international aviation turbo prices.

---

[16] See Transport Canada "Transportation Demand and Oil Use to 1990" February, 1982.

[17] This was discussed at some length in the Ministry's previous forecast.

[18] Air transport activity in B.C. is not solely a function of economic conditions in the province, since most trips involve either an origin or destination outside the province. The demand for air transport is influenced by the health of broader economies.

Requirements may be lower than they otherwise would have been as a result of the transfer of Pacific Western's headquarters to Edmonton.

Requirements for aviation gasoline have declined since 1960 and, from the early seventies, have settled at the level of about 1.5 PJ per year. Most usage is centered in the general aviation category which includes government and private aircraft, while small amounts are used by domestic carriers.

6.4.3 Forecast Period Assumptions

Forecasts of the factors governing the demand for aviation turbo fuel and aviation gasoline requirements are discussed separately below.

6.4.3.1 Aviation Turbo Fuel

Aviation turbo fuel requirements have been determined by the volume of air traffic, as measured by the number of passengers carried, and the real price of turbo fuel. In turn, the number of passengers carried has been linked to population, real disposable income and an index of the cost of air travel. This latter variable is related to a measure of overall costs, the consumer price index, and the price of aviation turbo fuel.

Fuel Price and Cost of Air Travel

A forecast of aviation turbo fuel prices and supporting rationale have already been presented in Chapter 2. To recap, it is anticipated that real aviation turbo prices will decline between 1983 and 1987 after which they will increase, at a moderate rate, until the year 2000. Over the entire 1981 to 2000 period real aviation turbo fuel prices increase at an average annual rate of about 1.2 percent.

Coupled with the forecast of consumer price increases discussed in Chapter 2, the real cost of air travel, as reported in Table 6.4.1, will grow modestly throughout the forecast period to a level 7.3 percent higher than in 1980.

Number of Passengers

As noted, the number of passengers has been forecast on the basis of real disposable income and a measure of the real cost of air travel. Preliminary estimates for 1984 indicate that the number of passengers is about 7 percent below the historical high of 7.4 million passengers in 1981. Table 6.4.1 shows that the number of passengers is not expected to reach 1981 levels until 1986 when an influx of tourists for Expo '86 is anticipated. After Expo '86, the growth in the number of passengers is anticipated to return to more normal levels and grow at an average of about 1.0 percent annually until the year 2000.

Table 6.4.1

Number of Passengers and Cost of Air Travel

	Number of Passengers* (000)	Cost of Travel (1971$-Index)
1980	7358	1.09
1981	7394	1.13
1982	7062	1.15
1983	6928	1.16
1984	6917	1.15
1985	6933	1.13
1986	7872	1.15
1990	7253	1.15
1995	7765	1.16
2000	8910	1.17

---

* Estimated total number of passengers enplaned and deplaned at B.C. airports.

6.4.3.2 Aviation Gasoline

For the most part, aviation gasoline is used in the general (i.e. non-scheduled) aviation category which includes government and private aircraft. Estimates for 1979 indicated these volumes amounted to about 1.3 PJ or 82 percent of total aviation gasoline requirements. The entire remainder was accounted for by domestic airlines.

For the purpose of this forecast, aviation gasoline requirements have not been forecast using an econometrically specified relationship. Past efforts at using econometric techniques did not prove successful. Thus, the Ministry has projected requirements judgementally, taking into account those factors (e.g. fuel prices) which play a role in determining requirements.

6.4.4 Total Energy and Fuels Requirements

6.4.4.1 Aviation Turbine Fuel

Total energy and aviation turbine fuel requirements are forecast to be at 1981 levels in the year 2000, as shown in Table 6.4.2. Requirements for aviation turbo fuel declined by about 29 percent between 1981 and 1984 and are anticipated to remain weak over the short term in light of the sluggish economic recovery. Moreover, it is anticipated that in response to the fuel price increases which occured in the 1979-1981 period, airlines will continue to reduce service, reduce air speed and improve scheduling in order to reduce fuel useage. Also, measures will be undertaken to reduce costs by increasing load factors through better alignment of aircraft and loads.

TABLE 6.4.2

AIR SECTOR
ENERGY REQUIREMENTS

(PETAJOULES)

YEAR	AVIATION GASOLINE	AVIATION TURBO	TOTAL REQTS
1978	1.518	19.258	20.776
1979	1.619	23.168	24.787
1980	1.549	24.679	26.228
1981	1.361	24.352	25.713
1982	1.001	19.648	20.649
1983	1.084	18.833	19.917
1984	1.208	18.963	20.171
1985	1.301	19.114	20.415
1986	1.332	22.102	23.434
1987	1.332	21.538	22.870
1988	1.332	21.035	22.367
1989	1.332	20.479	21.811
1990	1.332	19.929	21.261
1991	1.332	19.507	20.839
1992	1.332	19.157	20.489
1993	1.332	19.859	21.191
1994	1.332	20.557	21.889
1995	1.332	21.225	22.557
1996	1.332	21.918	23.250
1997	1.332	22.543	23.875
1998	1.332	23.108	24.440
1999	1.332	23.716	25.048
2000	1.332	24.312	25.644

ANNUAL GROWTH RATES

1981-1990	¯.24	¯2.20	¯2.09
1990-2000	.00	2.01	1.89
1981-2000	¯.11	¯.01	¯.01

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

Fuel requirements however are anticipated to increase in 1986 with Expo '86, but will return to levels more reflective of the major underlying factors in the post Expo period. It is anticipated that airlines will continue to modernize their fleets with more fuel efficient planes.

Requirements are, however, anticipated to grow by an average annual rate of 2.0 percent between 1990 and the year 2000 from 19.9 PJ to 24.3 PJ. Passenger growth averages 2.1 percent during the nineties, reflecting stable real travelling costs (see Table 6.4.1) and rising real incomes.

6.4.4.2 Aviation Gasoline

It is anticipated that aviation gasoline requirements will decline as the price increases of the 1979/81 period are digested. Beyond 1985, requirements have been held constant at a level slightly higher than that in 1985 to reflect the impact of higher economic growth partly offset by rising fuel prices.

CHAPTER 7

NON-ENERGY USE

7.0 Introduction

While refined petroleum products are used principally to provide energy, some of these products also have significant use in non-energy applications. The key refined petroleum products used for non-energy applications include asphalts, lubricating oils and greases, and petroleum coke. This chapter provides estimates of future demand for these products and discusses the rationale which underlies these forecasts. Also included in this chapter is a discussion of natural gas requirements used as a feedstock for the petrochemical industry in British Columbia. A brief overview of the historical demand for these non-energy use products is presented first.

7.1 Historical Perspective

In the early sixties the demand for non-energy use products averaged about 13.0 petajoules. Since then the requirements for these products have grown consistently at a rate of about 6.0 percent per year[1] and peaked in 1978 at a level of 33 petajoules. The latest actual record (i.e. 1981) however, indicates a drop from this 1978 level of about 4 petajoules to 29 petajoules.

Historically, asphalt and petroleum coke constituted a significant portion of these non-energy requirements in British Columbia. These two products together averaged over 70 percent of the total non-energy use. Lubricating oils and greases accounted for another 17 percent and the rest of the non-energy demand included naphtha specialties, waxes and other products.

---

[1] Calculated over 16 year period from 1962 to 1978.

7.2 Forecast Requirements

7.2.1 Refined Petroleum Products

Refined petroleum products demand for non-energy use is estimated by developing separate forecasts for asphalts, lubricating oils and greases, based on relationships discussed in the Ministry's model documentation.[2] The demand for petroleum coke and "other products" is determined exogenously.

Since asphalt is used principally for paving roads and highways, the demand for this product is expected to be dependent on the level of highways activity which in turn is determined by the level of economic activity. However, other considerations such as blending of asphalt with sulphur, use of recycled asphalt and the applications of new substitutes are expected to lower demand for asphalt. The use of concrete, on the other hand, is not likely to effect the future demand for asphalt in the province due to the prohibitive maintenance and resurfacing costs associated with concrete use. In recognition of these extraneous factors, the forecast estimates were adjusted based on the comparison of predicted and actual requirements for the 1978 to 1982 period.

---

[2] "The B.C. Energy Demand Forecasting and Planning Model" Staff Paper MEMPR, March 1983.

The demand for petroleum coke is currently met almost entirely by extra-provincial sources, mostly from the United States and Alberta. In British Columbia, petroleum coke is used predominantly for the manufacture of anodes for use in aluminum smelters by Alcan. Alcan's current consumption of petroleum coke alone represents over 60 percent of the total provincial consumption. It is expected that this consumption will stay at the current level until new smelters come on stream in the 1990's. With the new smelters, Alcan's production of aluminum is expected to increase by 76 percent in 1990 and by another 43 percent in 1998. Concomitant with these changes in aluminum production levels, the demand for petroleum coke at Alcan is expected to increase proportionately from the current level of about 5.0 petajoules per year to 9.0 petajoules per year in 1990, and to 12.8 petajoules in 2000.

Demand for lubricating oils and greases is forecast to increase in line with the growth in construction, mining, and transportation and communication industries. The demand for "other products" which includes naphtha specialties is forecast to grow at the same rate as the demand for asphalt, lubricating oil, and greases.

As indicated in Table 7.1, refined petroleum products demand for non-energy applications is forecast to increase from 29.0 petajoules in 1981 to 48.4 petajoules in 2000 indicating an annual average growth rate of 2.7 percent. The demand for asphalt is expected to increase from a level of about 13.0 petajoules in 1981, to 20.0 petajoules in 2000 indicating an annual average growth of 2.2 percent per annum. The demand for lubricating oils and greases is forecast to increase at a rate of 2.3 percent per annum from 4.3 petajoules in 1981 to 6.6 petajoules in 2000.

TABLE 7.1

FORECAST OF REFINED PETROLEUM PRODUCT REQUIREMENTS FOR NON-ENERGY USE

(PETAJOULES)

YEAR	ASPHALT	LUBES AND GREASES	PETROLEUM COKE	OTHER PRODUCTS	TOTAL
1978	15.424	4.147	11.217	2.476	33.264
1979	15.164	4.406	8.666	2.167	30.403
1980	14.913	4.632	8.670	3.380	31.595
1981	13.061	4.338	7.856	3.722	28.977
1982	9.296	3.919	1.606	3.106	17.927
1983	10.401	4.315	3.169	3.459	21.344
1984	11.124	4.547	4.732	3.684	24.087
1985	11.711	4.727	6.295	3.864	26.597
1986	12.091	4.822	7.858	3.976	28.747
1987	12.432	4.904	7.858	4.075	29.269
1988	12.856	5.015	7.858	4.201	29.930
1989	13.341	5.146	7.858	4.346	30.691
1990	13.839	5.261	11.714	4.490	35.304
1991	14.354	5.379	11.714	4.638	36.085
1992	14.898	5.512	11.714	4.798	36.922
1993	15.481	5.654	11.714	4.968	37.817
1994	16.092	5.797	11.714	5.145	38.748
1995	16.713	5.941	11.714	5.325	39.693
1996	17.346	6.087	11.714	5.508	40.655
1997	17.984	6.229	11.714	5.692	41.619
1998	18.621	6.367	15.570	5.874	46.432
1999	19.268	6.506	15.570	6.059	47.403
2000	19.911	6.640	15.570	6.241	48.362
			ANNUAL GROWTH RATES		
1981-1990	.64	2.17	4.54	2.11	2.22
1990-2000	3.70	2.36	2.89	3.35	3.20
1981-2000	2.24	2.27	3.67	2.76	2.73

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

As noted above, the increase in the demand for petroleum coke is anticipated to come principally from the operation of new smelters in 1990's. These operations are expected to increase petroleum coke demand from 7.9 petajoules in 1981 to 15.6 petajoules by the end of the forecast period. The demand for "other products" is forecast to increase at an annual average growth rate of 2.8 percent.

7.2.2 Feedstock Requirements

Table 7.2 presents the natural gas requirements as a feedstock in the petrochemical industry. These estimates were developed earlier in subsectors 5.2 and 5.6 of the industrial sector. However, as these fuel demands represent a non-energy use, these estimates are netted out of the industrial sector energy requirements shown in Chapter 5 and are reported here.

The demand for natural gas as a feedstock is forecast to increase from a level of 5.7 petajoules in 1982 to 101.0 petajoules in 1988 and to 124.4 petajoules by 2000. The substantial growth expected during the 1982-1988 period reflects the assumptions that by 1984, the Ocelot Methanol plant at Kitimat will be fully operational and in addition, an Ammonia-Urea fertilizer manufacturing plant and the proposed LNG facility will be in place.

The natural gas requirements for the LNG project shown in Table 7.2 represents a 50 percent share of total demand to be supplied by British Columbia gas.

TABLE 7.2

PETROCHEMICALS AND LIQUEFIED NATURAL GAS SECTOR FEEDSTOCK REQUIREMENTS

(PETAJOULES)

YEAR	LIQUEFIED NAT, GAS	PETRO- CHEMICALS	TOTAL
1978	.000	.000	.000
1979	.000	.000	.000
1980	.000	.000	.000
1981	.000	.000	.000
1982	.000	5.682	5.682
1983	.000	14.620	14.620
1984	.000	15.457	15.457
1985	.000	15.501	15.501
1986	.000	15.546	15.546
1987	.000	19.261	19.261
1988	65.229	35.778	101.007
1989	78.575	37.667	116.242
1990	81.532	37.727	119.259
1991	85.987	37.789	123.776
1992	85.987	37.852	123.839
1993	85.987	37.917	123.904
1994	85.987	37.982	123.969
1995	85.987	38.049	124.036
1996	85.987	38.118	124.105
1997	85.987	38.188	124.175
1998	85.987	38.259	124.246
1999	85.987	38.331	124.318
2000	85.987	38.405	124.392
ANNUAL GROWTH RATES			
1981-1990	.00	.00	.00
1990-2000	.53	.18	.42
1981-2000	.00	.00	.00

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

CHAPTER 8

TOTAL ENERGY REQUIREMENTS

8.0 Introduction

This chapter provides a summary of total end-use and primary energy requirements in British Columbia for a 20 year period starting in 1981 through to 2000. In addition, this chapter also presents demand for primary fuels in the province.

The end-use energy requirements included in this chapter refer to energy use in its final form in residential, commercial, industrial and transport sectors. The primary energy demand, on the other hand, is derived from the end-use requirements by adding energy used in the energy supply industries including distribution and transmission losses. Fuel consumed in thermal generation is also included in the primary energy totals; thermal electricity, however, is excluded. Finally, the primary fuel requirements estimates are summarized by adding to the primary energy totals the non-energy related consumption of refined petroleum products and the natural gas requirements used as feedstocks in the petrochemical/LNG industries.

8.1 Total End-Use Energy Requirements

Total end-use energy requirements in British Columbia are forecast to increase at an annual average rate of 1.3 percent from 829 petajoules in 1981 to 1060 petajoules by 2000. These requirements are presented by consuming sector and by fuel type in Tables 8.1 and 8.2 and a brief commentary is included.

TABLE 8.1

PROVINCIAL (END USE) ENERGY REQUIREMENTS BY SECTOR

(PETAJOULES)

YEAR	RESIDENTIAL	COMMERCIAL	PULP AND PAPER	WOOD PRODUCTS	CHEMICALS	OTHER	MINING	PETRO/LNG	OTHER IND,	ROAD	AIR	MARINE	RAIL	TOTAL REQTS
1978	117.284	74.261	237.555	51.614	11.289	57.316	20.444	.000	17.803	160.243	20.777	19.485	8.833	796.904
1979	120.169	80.008	239.427	50.630	11.296	58.949	21.243	.000	19.222	172.290	24.787	24.284	9.448	831.753
1980	121.714	82.269	248.207	50.059	11.575	58.136	22.446	.000	21.348	182.740	26.228	34.880	10.187	869.789
1981	117.060	80.895	214.761	42.241	10.599	57.199	23.716	.000	19.812	181.299	25.713	44.423	10.867	828.585
1982	123.657	82.053	220.557	39.265	10.008	53.364	22.010	.061	18.891	166.874	20.649	36.266	10.176	803.911
1983	127.857	78.586	225.728	47.966	10.596	53.813	21.740	.128	20.058	163.290	19.917	21.988	9.852	801.519
1984	128.627	78.086	229.109	48.706	10.909	55.196	27.312	.137	20 587	159.849	20.171	18.095	10.703	807.487
1985	130.428	78.595	228.410	50.896	11.073	56.859	32.139	.137	21.177	155.724	20.415	20.643	11.960	818.456
1986	130.012	79.194	220.753	47.607	10.785	37.150	31.844	.137	20.559	152.500	23.434	32.239	13.184	819.398
1987	130.878	80.085	222.224	49.625	10.912	59.243	31.750	.256	20.762	149.917	22.870	33.424	14.375	826.321
1988	133.125	81.396	229.354	51.550	11.214	59.961	31.911	3.146	21.403	148.126	22.367	35.371	15.349	844.273
1989	135.584	82.803	235.724	51.768	11.337	60.819	31.965	3.723	21.694	146.923	21.811	36.800	15.722	856.673
1990	137.783	84.286	240.812	51.899	11.454	71.308	31.624	3.851	21.854	145.945	21.261	37.754	15.790	875.621
1991	137.843	86.129	247.049	52.316	11.646	73.636	32.968	4.043	22.252	146.402	20.839	39.313	15.913	890.349
1992	140.410	88.363	248.479	53.600	11.745	74.567	33.936	4.043	22.869	147.748	20.489	41.328	16.093	903.670
1993	143.133	91.004	254.220	54.170	11.872	75.611	34.685	4.043	23.209	149.935	21.191	43.039	16.258	922.370
1994	146.020	94.138	256.264	54.154	11.889	76.639	35.202	4.043	23.535	152.823	21.889	44.331	16.458	937.385
1995	149.004	97.564	264.843	53.759	12.081	77.703	35.632	4.043	23.782	156.277	22.557	45.489	16.720	959.454
1996	149.991	101.220	269.322	54.099	12.195	78.707	35.844	4.043	24.034	160.185	23.250	46.574	16.852	976.316
1997	153.207	104.949	273.596	54.103	12.310	81.023	38.741	4.043	24.258	164.430	23.875	47.657	16.822	999.014
1998	156.343	108.669	277.093	53.743	12.426	82.020	38.929	4.043	24.488	168.983	24.440	48.746	16.835	1017.558
1999	159.532	112.465	280.653	54.106	12.510	92.712	39.118	4.043	24.725	173.845	25.048	49.850	16.834	1045.441
2000	162.557	116.310	280.461	54.149	12.541	93.606	39.314	4.043	24.925	178.905	25.644	50.953	16.835	1060.243
							ANNUAL GROWTH RATES							
1981-1990	1.83	.46	1.28	2.31	.87	2.48	3.25	.00	1.10	¯2.38	¯2.09	¯1.79	4.24	.62
1990-2000	1.67	3.27	1.54	.43	.91	2.76	2.20	.49	1.32	2.06	1.89	3.04	.64	1.93
1981-2000	1.74	1.93	1.41	1.32	.89	2.63	2.70	.00	1.22	¯.07	¯.01	.72	2.33	1.31

* OTHER INCLUDES PRIMARY METALS (PURCHASED), NON-METALLICS, REFINERIES, OTHER MANUFACTURING AND OTHER INDUSTRIAL,

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

TABLE B.2

FORECAST OF TOTAL (END-USE)* FUEL REQUIREMENTS

(PETAJOULES)

YEAR	TOTAL R.P.P.	ELECTRICITY PURCHASED	ELECTRICITY SELF-GEN.	ELECTRICITY SUB-TOTAL	NATURAL GAS	OTHER	TOTAL REQTS
1978	330.475	98.148	28.688	126.836	144.232	195.357	796.900
1979	354.888	104.532	27.831	132.363	153.880	190.622	831.753
1980	369.723	109.958	28.378	138.336	159.437	202.290	869.786
1981	364.750	107.649	28.617	136.266	155.145	172.423	828.584
1982	332.761	110.555	28.314	138.869	157.688	174.593	803.911
1983	308.026	116.156	28.960	145.116	157.961	190.416	801.519
1984	300.573	121.857	29.139	150.996	161.384	194.536	807.489
1985	300.648	126.429	29.324	155.753	163.355	198.700	818.456
1986	298.554	126.426	29.324	155.750	172.593	192.502	819.399
1987	296.520	127.613	30.900	158.513	173.255	198.034	826.322
1988	298.615	132.310	30.900	163.210	174.064	208.386	844.275
1989	298.554	134.003	30.900	164.903	174.336	218.879	856.672
1990	301.465	133.684	40.620	174.304	174.620	225.233	875.622
1991	306.817	136.506	40.620	177.126	175.058	231.347	890.348
1992	313.686	139.601	40.620	180.221	177.233	232.530	903.670
1993	320.165	142.893	40.620	183.513	180.413	238.278	922.369
1994	327.014	146.693	40.620	187.313	184.250	238.807	937.384
1995	334.493	149.693	40.620	190.313	189.094	245.554	959.454
1996	339.846	152.805	40.620	193.425	192.889	250.158	976.318
1997	347.334	157.228	41.945	199.173	197.600	254.907	999.014
1998	354.551	160.709	41.945	202.654	202.258	258.096	1017.559
1999	362.007	167.043	48.785	215.828	206.722	260.884	1045.441
2000	369.098	170.177	48.785	218.962	210.646	261.538	1060.244
ANNUAL GROWTH RATES							
1981-1990	¯2.10	2.44	3.97	2.77	1.32	3.01	.62
1990-2000	2.04	2.44	1.85	2.31	1.89	1.51	1.93
1981-2000	.06	2.44	2.85	2.53	1.62	2.22	1.31

---

* THE NATURAL GAS ESTIMATES SHOWN EXCLUDE GAS USED AS A FEEDSTOCK AT OCELOT, DOME AND AMMONIA-UREA FACILITIES. R.P.P.'S INCLUDE L.P.G.'S. THE OTHER CATEGORY INCLUDES HOG FUEL, WASTE LIQUOR, COAL, OTHER BY-PRODUCTS AND RENEWABLES.

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

8.1.1 Energy Requirements by Sector

The industrial sector currently accounts for about 44 percent of total energy requirements, while the transport sector uses 32 percent, the residential sector consumes 14 percent and the commercial sector accounts for the remaining 10 percent (Table 8.1). Over the forecast period, energy requirements in both residential and industrial sectors are expected to grow at an average rate of 1.7 percent per annum. The commercial sector requirements are forecast to increase at a slightly higher rate of 1.9 percent; the transport energy demand, however, is expected to increase very modestly from 262.3 petajoules in 1981 to 272.3 petajoules by 2000 indicating an annual average growth rate of 0.2 percent.

8.1.2 Energy Requirements by Fuel Type

Energy requirements by fuel type are summarized in Table 8.2 and are discussed by individual fuel in the following sections.

8.1.2.1 Electricity

The total provincial electricity requirements (including self-generated hydroelectricity) are forecast to increase from 136.3 petajoules in 1981 to 219.0 petajoules in 2000 indicating an annual average growth rate of 2.5 percent (Table 8.3). Self-generated hydroelectricity currently supplies about 21 percent of total electricity demand in British Columbia. It is expected that it will continue to maintain its share around the current level over the entire forecast period.

Electricity is expected to be the fastest growing end-use fuel. This relatively rapid growth is a reflection of a combination

TABLE 8.3

ELECTRICITY REQUIREMENTS BY SECTOR

(PETAJOULES)

YEAR	RESIDENTIAL	COMMERCIAL	PULP AND PAPER	WOOD PRODUCTS	CHEMICALS	OTHER	MINING	PETRO/LNG	ROAD	RAIL	SUB-TOTAL	SELF-GEN ELECTRICITY	TOTAL REQTS
1978	29.703	25.054	16.671	7.133	5.271	5.285	8.850	.000	.180	.000	98.147	28.689	126.836
1979	31.145	28.340	17.130	7.413	5.656	5.541	9.129	.000	.180	.000	104.534	27.831	132.365
1980	33.367	30.267	17.309	7.418	5.822	5.902	9.701	.000	.173	.000	109.959	28.378	138.337
1981	33.660	29.231	15.212	6.724	5.343	6.038	11.265	.000	.176	.000	107.649	28.617	136.266
1982	35.969	30.085	16.796	6.081	5.050	5.415	10.918	.061	.180	.000	110.555	28.315	138.870
1983	38.693	30.448	18.710	6.422	5.188	5.387	11.001	.128	.180	.000	116.157	28.961	145.118
1984	41.122	30.684	19.513	6.542	5.352	5.600	12.629	.137	.180	.099	121.858	29.139	150.997
1985	43.246	31.014	19.276	6.605	5.405	5.835	14.601	.137	.180	.130	126.429	29.324	155.753
1986	44.237	31.428	18.458	6.207	5.261	5.904	14.321	.137	.330	.144	126.427	29.324	155.751
1987	44.915	31.862	18.491	6.242	5.306	6.002	14.067	.256	.330	.144	127.615	30.901	158.516
1988	45.390	32.416	18.811	6.378	5.469	6.146	14.082	3.146	.330	.144	132.312	30.901	163.213
1989	45.994	33.139	18.342	6.292	5.601	6.301	14.130	3.723	.330	.153	134.005	30.901	164.906
1990	46.650	33.939	18.016	6.209	5.730	6.818	11.965	3.851	.326	.181	133.685	40.621	174.306
1991	47.314	34.744	17.573	6.217	5.860	8.790	11.457	4.043	.326	.183	136.507	40.621	177.128
1992	48.135	35.585	18.951	6.253	5.870	9.108	11.144	4.043	.326	.186	139.601	40.621	180.222
1993	48.948	36.483	20.365	6.210	5.963	9.442	10.925	4.043	.326	.189	142.894	40.621	183.515
1994	49.826	37.631	21.866	6.177	5.982	9.783	10.867	4.043	.326	.191	146.692	40.621	187.313
1995	50.750	38.915	22.155	6.126	6.175	10.141	10.865	4.043	.326	.194	149.692	40.621	190.313
1996	51.749	40.321	22.450	6.104	6.292	10.347	10.976	4.043	.326	.197	152.805	40.621	193.426
1997	52.939	41.811	22.749	6.071	6.409	10.554	12.080	4.043	.326	.246	157.228	41.945	199.173
1998	54.176	43.336	23.058	6.026	6.529	10.765	12.200	4.043	.326	.250	160.709	41.945	202.654
1999	55.455	44.913	23.258	6.005	6.617	13.850	12.322	4.043	.326	.253	167.042	48.785	215.827
2000	56.688	46.518	23.236	5.975	6.652	14.038	12.443	4.043	.326	.257	170.176	48.785	218.961
						ANNUAL GROWTH RATES							
1981-1990	3.69	1.67	1.90	-.88	.78	1.36	.67	.00	7.09	.00	2.44	3.97	2.77
1990-2000	1.97	3.20	2.58	-.38	1.50	7.49	.39	.49	.00	3.57	2.44	1.85	2.31
1981-2000	2.78	2.48	2.25	-.62	1.16	4.54	.52	.00	3.30	.00	2.44	2.85	2.53

1 OTHER INCLUDES PRIMARY METALS (PURCHASED), NON-METALLICS, REFINERIES, OTHER MANUFACTURING AND OTHER INDUSTRIAL,

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,

JUNE 1984

of factors which include, for example, industrial expansions in the electricity intensive primary metals industry, slower growth in electricity prices relative to natural gas, and the incentives provided under federal and provincial initiatives to curtail consumption of oil.

Table 8.3 also shows electricity requirements by consuming sector. Residential electricity demand is expected to experience a relatively healthy growth rate of about 2.8 percent per annum. The electricity consumption in the commercial sector is expected to grow at approximately the same rate as the total provincial requirements whereas the industrial demand for electricity is forecast to grow at a slightly lower rate of about 2.1 percent per annum.

8.1.2.2 Natural Gas

The end-use energy demand for natural gas is forecast to increase from 155.1 petajoules in 1981 to 210.6 petajoules in 2000 indicating an annual average growth rate of 1.6 percent (Table 8.4).

The natural gas requirements estimates are further broken down by consuming sector in this table.

Compared to the overall growth rate of 1.6 percent the residential demand for natural gas is forecast to grow at an annual rate of 1.8 percent from 56.0 petajoules in 1981 to

TABLE 8.4

NATURAL GAS END-USE ENERGY REQUIREMENTS BY SECTOR

(PETAJOULES)

YEAR	RESIDENTIAL	COMMERCIAL	PULP AND PAPER	WOOD PRODUCTS	CHEMICALS	OTHER	MINING	TRANSPORT	TOTAL REQTS
1978	51.062	30.861	21.472	11.767	3.560	21.446	4.064	.000	144.232
1979	54.092	33.123	25.157	11.134	3.292	22.661	4.421	.000	153.880
1980	56.349	33.624	28.429	10.555	3.153	22.963	4.364	.000	159.437
1981	56.030	33.227	25.439	8.758	2.743	23.885	5.063	.000	155.145
1982	61.276	34.412	25.834	8.330	2.617	21.046	4.153	.020	157.688
1983	64.886	33.866	22.245	9.011	2.949	20.837	4.092	.075	157.961
1984	65.587	33.814	22.482	9.224	3.067	21.642	5.419	.149	161.384
1985	66.747	34.039	21.932	8.990	3.159	22.251	5.973	.264	163.355
1986	67.966	35.622	28.859	9.354	3.001	21.779	5.338	.674	172.593
1987	68.493	36.891	28.825	9.325	3.061	19.804	5.401	1.455	173.255
1988	69.475	37.475	29.340	9.274	3.184	17.668	5.379	2.269	174.064
1989	70.541	38.066	28.198	8.940	3.184	16.967	5.354	3.086	174.336
1990	71.366	38.667	29.050	8.666	3.184	16.450	3.852	3.385	174.620
1991	69.790	39.374	30.210	8.488	3.248	16.588	3.627	3.733	175.058
1992	70.092	40.458	30.483	8.367	3.331	16.915	3.473	4.114	177.233
1993	70.763	41.672	31.111	8.278	3.361	17.345	3.351	4.532	180.413
1994	71.879	43.100	31.635	8.219	3.357	17.796	3.281	4.983	184.250
1995	73.139	44.706	32.713	8.226	3.352	18.260	3.235	5.463	189.094
1996	73.047	46.403	34.037	8.161	3.350	18.691	3.231	5.969	192.889
1997	74.421	48.111	34.603	8.103	3.348	19.137	3.381	6.496	197.600
1998	75.757	49.829	35.240	8.081	3.346	19.582	3.380	7.043	202.258
1999	77.130	51.566	35.698	7.991	3.344	20.004	3.378	7.611	206.722
2000	78.445	53.343	35.609	7.942	3.344	20.397	3.375	8.191	210.646
				ANNUAL GROWTH RATES					
1981-1990	2.72	1.70	1.49	¯.12	1.67	¯4.06	¯2.99	.00	1.32
1990-2000	.95	3.27	2.06	¯.87	.49	2.17	¯1.31	9.24	1.89
1981-2000	1.79	2.52	1.79	¯.51	1.05	¯.83	¯2.11	.00	1.62

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

78.4 petajoules in 2000. The corresponding growth rates for commercial and industrial sectors are 2.5 percent and 0.3 percent respectively. As noted elsewhere in this report, the natural gas estimates are developed on the premise that the natural gas service would be extended to Vancouver Island beginning in 1986[1].

The demand for compressed natural gas for transportation purposes is forecast to reach a level of 8.2 petajoules by the year 2000.

The natural gas demand for Vancouver Island is shown separately in Table 8.5.

The total (end-use) natural gas requirements for Vancouver Island are forecast to increase from 12.8 petajoules in 1986 to 29.4 petajoules in 2000. As is evident from the table, both residential and commercial loads are expected to increase steadily; the industrial load, however, is expected to build up quickly with the conversion of Island pulp and paper mills to natural gas from heavy fuel oil.

---

[1] The natural gas estimates shown in this forecast are based on the assumption that the pipeline would follow the proposed southern route.

TABLE 8.5

FORECAST OF NATURAL GAS REQUIREMENTS; VANCOUVER ISLAND-SOUTHERN ROUTE

(PETAJOULES)

YEAR	RESIDENTIAL	COMMERCIAL	LIGHT INDUSTRIAL	HEAVY INDUSTRIAL	ROAD	TOTAL REQTS
1978	.000	.000	.000	.000	.000	.000
1979	.000	.000	.000	.000	.000	.000
1980	.000	.000	.000	.000	.000	.000
1981	.000	.000	.000	.000	.000	.000
1982	.000	.000	.000	.000	.000	.000
1983	.000	.000	.000	.000	.000	.000
1984	.000	.000	.000	.000	.000	.000
1985	.000	.000	.000	.000	.000	.000
1986	2.181	1.383	1.209	8.031	.000	12.804
1987	3.271	2.438	1.257	8.245	.126	15.337
1988	4.420	2.757	1.314	8.595	.182	17.268
1989	5.623	3.081	1.340	8.705	.245	18.994
1990	6.876	3.401	1.363	8.936	.313	20.889
1991	6.953	3.577	1.392	9.295	.392	21.609
1992	7.336	3.831	1.420	9.618	.468	22.673
1993	7.721	3.970	1.442	9.334	.551	23.018
1994	8.116	4.098	1.464	9.663	.642	23.983
1995	8.521	4.260	1.490	10.081	.738	25.090
1996	8.547	4.417	1.508	11.096	.839	26.407
1997	8.809	4.563	1.525	11.354	.944	27.195
1998	9.071	4.724	1.544	11.678	1.054	28.071
1999	9.340	4.872	1.560	11.949	1.167	28.888
2000	9.605	5.038	1.575	11.939	1.283	29.440

ANNUAL GROWTH RATES

1981-1990	.00	.00	.00	.00	.00	.00
1990-2000	3.40	4.01	1.46	2.94	15.14	3.49
1981-2000	.00	.00	.00	.00	.00	.00

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

8.1.2.3 Liquid Hydrocarbons

For the purpose of this forecast, liquid hydrocarbons are defined to include all refined petroleum products and liquefied petroleum gases. The forecast demand for these liquid hydrocarbons by product and by consuming sector is summarized in Tables 8.6 and 8.7.

The total demand for liquid hydrocarbons is forecast to increase from 365 petajoules in 1981 to 369 petajoules by 2000 (Table 8.6). Except for diesel oil and liquefied petroleum gases, the consumption of all other products is expected to decline largely as a result of inter-fuel substitution and energy conservation. In addition, the displacement of heavy fuel oil by natural gas and hog fuel in the pulp and paper industry is another key factor contributing to this decline.

The demand for liquefied petroleum gases is forecast to grow at an annual average rate of 1.9 percent. This growth is a result of the increased application of this fuel in the road transport sector.

As shown in Table 8.7, both residential and commercial use of refined petroleum products are forecast to decline in response to the government policies and incentives designed to reduce dependence on imported oil products. The industrial use of refined petroleum products, however, is forecast to increase from 57.8 petajoules in 1981 to 65.7 petajoules in 2000. This increase in the industrial demand is, to a large extent, attributable to the growth in mining sector in the 1990's.

TABLE 8.6

REFINED PETROLEUM PRODUCTS (RPP) END USE ENERGY REQUIREMENTS BY FUEL

(PETAJOULES)

YEAR	AVIATION GASOLINE	AVIATION TURBO	DIESEL FUEL OIL	HEAVY FUEL OIL	LIGHT FUEL OIL	L.P.G.	MOTOR GASOLINE	TOTAL REQTS
1978	1.518	19.258	75.399	48.620	38.220	7.782	139.678	330.475
1979	1.619	23.168	84.864	53.228	38.300	7.991	145.718	354.888
1980	1.549	24.679	94.689	54.792	33.396	8.481	152.137	369.723
1981	1.361	24.352	90.451	62.121	26.786	7.674	152.005	364.750
1982	1.001	19.648	83.838	53.190	27.046	8.190	139.848	332.761
1983	1.084	18.833	82.568	37.497	23.789	7.591	136.664	308.026
1984	1.208	18.963	84.651	33.467	21.587	7.219	133.478	300.573
1985	1.301	19.114	88.544	34.553	20.335	7.113	129.688	300.648
1986	1.332	22.102	89.245	37.138	16.795	5.904	126.038	298.554
1987	1.332	21.538	90.692	38.411	15.889	5.667	122.991	296.520
1988	1.332	21.035	93.386	40.274	16.233	5.933	120.422	298.615
1989	1.332	20.479	94.907	40.946	16.531	6.192	118.167	298.554
1990	1.332	19.929	98.588	42.232	16.739	6.488	116.157	301.465
1991	1.332	19.507	103.054	43.668	17.316	6.925	115.015	306.817
1992	1.332	19.157	107.626	45.229	18.252	7.434	114.656	313.686
1993	1.332	19.859	110.663	46.214	19.089	7.976	115.032	320.165
1994	1.332	20.557	113.309	47.654	19.621	8.489	116.052	327.014
1995	1.332	21.225	115.789	49.492	20.050	8.978	117.627	334.493
1996	1.332	21.918	118.050	49.646	19.911	9.358	119.631	339.846
1997	1.332	22.543	120.394	51.055	20.217	9.825	121.968	347.334
1998	1.332	23.108	122.372	52.461	20.407	10.238	124.633	354.551
1999	1.332	23.716	124.348	53.811	20.581	10.644	127.575	362.007
2000	1.332	24.312	126.220	54.780	20.693	11.012	130.749	369.098

ANNUAL GROWTH RATES

1981-1990	¯.24	¯2.20	.96	¯4.20	¯5.09	¯1.85	¯2.94	¯2.10
1990-2000	.00	2.01	2.50	2.64	2.14	5.43	1.19	2.04
1981-2000	¯.11	¯.01	1.77	¯.66	¯1.35	1.92	¯.79	.06

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

TABLE 8.7

REFINED PETROLEUM PRODUCTS REQUIREMENTS BY SECTOR

(PETAJOULES)

YEAR	RESIDENTIAL	COMMERCIAL	PULP AND PAPER	WOOD PRODUCTS	CHEMICALS	OTHER	MINING	PETRO/LNG	ROAD	RAIL	MARINE	AIR	TOTAL REQTS
1978	36.474	18.345	31.133	3.425	.471	23.940	7.531	.000	160.063	8.833	19.485	20.776	330.476
1979	34.915	18.544	32.994	3.733	.865	25.515	7.693	.000	172.110	9.448	24.283	24.787	354.887
1980	31.995	18.378	26.705	3.735	.550	26.117	8.381	.000	182.567	10.187	34.880	26.228	369.723
1981	26.421	18.437	24.575	2.942	.337	22.527	7.389	.000	181.123	10.867	44.422	25.713	364.753
1982	26.412	17.556	23.721	2.733	.308	21.326	6.940	.000	166.674	10.176	36.267	20.649	332.762
1983	24.278	14.273	22.232	2.926	.346	22.535	6.646	.000	163.035	9.852	21.987	19.917	308.027
1984	21.919	13.588	23.265	2.976	.377	23.252	6.807	.000	159.519	10.605	18.095	20.171	300.574
1985	20.436	13.542	22.848	2.954	.395	24.077	8.225	.000	155.280	11.830	20.642	20.415	300.644
1986	17.598	12.144	14.507	2.312	.167	23.121	8.496	.000	151.670	13.040	32.065	23.434	298.554
1987	17.057	11.332	14.898	2.315	.177	23.467	8.619	.000	148.834	14.232	32.722	22.870	296.523
1988	17.622	11.505	15.420	2.328	.183	24.266	8.818	.000	146.774	15.205	34.124	22.367	298.612
1989	18.177	11.599	15.032	2.269	.179	24.730	8.884	.000	145.282	15.570	35.025	21.811	298.558
1990	18.671	11.680	15.375	2.218	.174	25.022	11.467	.000	144.009	15.609	35.979	21.261	301.465
1991	19.394	12.011	15.716	2.195	.173	25.527	13.575	.000	144.118	15.730	37.537	20.839	306.815
1992	20.579	12.320	16.116	2.185	.176	26.247	15.032	.000	145.082	15.907	39.553	20.489	313.686
1993	21.567	12.848	16.043	2.184	.177	26.679	15.289	.000	146.851	16.069	41.264	21.191	320.162
1994	22.178	13.407	16.543	2.181	.178	27.094	15.435	.000	149.298	16.266	42.555	21.889	327.014
1995	22.606	13.944	17.442	2.170	.179	27.428	15.583	.000	152.263	16.526	43.714	22.557	334.492
1996	22.476	14.497	16.688	2.161	.179	27.781	15.693	.000	155.666	16.655	44.799	23.250	339.845
1997	22.898	15.027	17.049	2.148	.179	28.099	16.308	.000	159.382	16.576	45.882	23.875	347.333
1998	23.041	15.504	17.496	2.133	.179	28.428	16.386	.000	163.389	16.585	46.971	24.440	354.552
1999	23.253	15.986	17.858	2.120	.177	28.761	16.463	.000	167.683	16.581	48.076	25.048	362.006
2000	23.381	16.450	17.822	2.109	.177	29.048	16.549	.000	172.162	16.578	49.177	25.644	369.097
						ANNUAL GROWTH RATES							
1981-1990	¯3.78	¯4.95	¯5.08	¯3.09	¯7.08	1.17	5.00	.00	¯2.52	4.11	¯2.31	¯2.09	¯2.10
1990-2000	2.28	3.48	1.49	¯.50	.17	1.50	3.74	.00	1.80	.60	3.17	1.89	2.04
1981-2000	¯.64	¯.60	¯1.68	¯1.74	¯3.33	1.35	4.34	.00	¯.27	2.25	.54	¯.01	.06

* OTHER INCLUDES PRIMARY METALS, NON-METALLICS, REFINERIES, OTHER MANUFACTURING AND OTHER INDUSTRIAL.

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,

JUNE 1984

The transport sector currently accounts for about 72.0 percent of the total liquid hydrocarbon demand in British Columbia. Significant reductions in road use of motor gasoline are forecast into the early 1990's in spite of an expanding automobile population because of increasing use of smaller and more fuel efficient passenger vehicles. Use of heavy fuel oil as marine bunker fuel is expected to grow as a result of assumed tax moderation and to reach former sales levels by the mid 1990's. Total demand for refined petroleum products in the transportation sector in the year 2000 will be about the same as in 1981.

8.1.2.4 Other Energy Sources

Except for about 4 petajoules of renewable energy which is expected to be consumed in the residential sector by the year 2000, all other energy types (hog fuel, waste liquor, coal and coke, and other by-product energy) are exclusively used in the industrial sector. The demand for these energy types (including renewables in the residential sector) is forecast to increase by 89 petajoules from 172.4 petajoules in 1981 to 261.5 petajoules by 2000 (Table 8.8).

8.2 Requirements for Energy Supply Industries

This section reports estimates of energy expended in the provision of the secondary energy requirements reported in the previous section. Energy in this section includes refinery own-use in the production and distribution of RPP's, pipeline fuel and losses in the transmission of natural gas, and losses in transmission and utility own-use of electricity.

Table 8.8

End-Use Energy Requirements of Other Energy Sources

(Petajoules)

Year	Coal and Coke	Hog Fuel	Pulping Liquors	Renewable Energy	Total Requirements
1981	1.0	64.3	107.2	--	172.4
1985	3.7	81.4	113.5	--	198.7
1990	12.7	92.5	119.0	1.1	225.2
1995	15.1	102.1	126.0	2.4	245.8
2000	17.3	106.1	134.1	4.0	261.5
AAG %					
1981-2000	16.2	2.7	1.2	--	2.2

Requirements in this section are reported by supply industry: electrical, natural gas and refineries and are summarized in Table 8.9.

8.2.1 Electricity

Consumption of electricity by the electricity supply industry includes estimates of B.C. Hydro's own-use, losses on the Cominco system and losses for five different end-use voltages on the B.C. Hydro and WKPL systems.

B.C. Hydro's own-use was determined as a fixed percentage of B.C. Hydro sales in each year. Losses on the Cominco system were set at 1.5 percent of electricity generated in the operation of its ammonia-urea plant and lead/zinc smelter.

Losses were estimated for the bulk, over 35 KW-primary, over 35 KW-secondary, under 35 KW-secondary and residential-secondary categories. Ratios of losses to sales in each of these categories were obtained for the fiscal year 1980/81. These ratios were then applied to requirements in the appropriate categories to obtain total losses.

Estimates of total electricity for the supply industries shown in Table 8.9 also include electricity used by oil and gas pipelines.

TABLE 8.9

LOSSES AND FUEL USED BY ENERGY SUPPLY INDUSTRIES

(PETAJOULES)

	NATURAL GAS			ELECTRICITY	OIL			
YEAR	LOSSES	BURRARD	SUB-TOTAL	LOSSES	OWN-USE	L.P.G.	SUB-TOTAL	TOTAL
1978	17.343	.568	17.911	14.076	15.901	.266	16.167	48.154
1979	19.732	5.656	25.388	13.891	18.181	.636	18.817	58.096
1980	15.982	7.017	22.999	14.069	17.590	.883	18.473	55.541
1981	14.459	.334	14.793	15.396	17.070	.756	17.826	48.015
1982	12.053	.380	12.433	14.847	14.475	.079	14.554	41.834
1983	12.538	2.000	14.538	15.617	14.604	.079	14.683	44.838
1984	12.662	2.000	14.662	16.338	15.617	.079	15.696	46.696
1985	13.133	2.000	15.133	16.947	15.658	.079	15.737	47.817
1986	13.960	2.000	15.960	17.077	15.525	.079	15.604	48.641
1987	14.329	2.000	16.329	17.304	15.422	.079	15.501	49.134
1988	17.795	2.000	19.795	17.747	15.419	.079	15.498	53.040
1989	18.534	2.000	20.534	17.988	15.392	.079	15.471	53.993
1990	18.854	2.000	20.854	18.095	15.757	.079	15.836	54.785
1991	19.302	5.000	24.302	18.435	16.172	.079	16.251	58.988
1992	19.600	5.000	24.600	18.818	16.585	.079	16.664	60.082
1993	19.946	5.000	24.946	19.214	16.947	.079	17.026	61.186
1994	20.361	5.000	25.361	19.671	17.296	.079	17.375	62.407
1995	20.840	5.000	25.840	20.085	17.665	.079	17.744	63.669
1996	21.217	5.000	26.217	20.524	18.012	.079	18.091	64.832
1997	21.692	5.000	26.692	21.109	18.408	.079	18.487	66.288
1998	22.217	5.000	27.217	21.609	18.778	.079	18.857	67.683
1999	22.686	5.000	27.686	22.325	19.172	.079	19.251	69.262
2000	23.124	5.000	28.124	22.805	19.484	.079	19.563	70.492
				ANNUAL GROWTH RATES				
1981-1990	2.99	22.00	3.89	1.81	¯.89	¯22.19	¯1.31	1.48
1990-2000	2.06	9.60	3.04	2.34	2.15	.00	2.14	2.55
1981-2000	2.50	15.31	3.44	2.09	.70	¯11.21	.49	2.04

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,

JUNE 1984

8.2.2 Natural Gas

Pipeline fuel and losses refer to natural gas consumed downstream of gas plants in compressors and heaters and those volumes unaccounted for or lost through meter inaccuracies. The estimates of pipeline fuel and losses presented here were prepared using the analysis developed for the Govier Inquiry on B.C.'s Requirements, Supply and Surplus of Natural Gas and Natural Gas Liquids. Reported as well are natural gas requirements used by utilities for the purpose of generating electricity.

Essentially, natural gas distribution losses were calculated by distribution utility based on 1981 volumes for end-use requirements. These 1981 values were used to proportion total provincial requirements by service area after which the 1981 ratios of losses to requirements were applied by service area. Requirements in B.C. Hydro's service area were however, separated into firm and interruptible categories before these ratios were applied.

Provision has also been made for natural gas in the generation of electricity by utilities. B.C. Hydro operates several facilities in the province where natural gas is used in the generation of electricity, including Burrard, Fort Nelson and Prince Rupert. The facility at Prince Rupert is an interruptible standby facility which uses little natural gas whereas the Fort Nelson facility provides electricity for the Fort Nelson area and is not currently connected to the B.C. Hydro integrated grid.

B.C. Hydro reported to the Govier Inquiry that the Burrard generating plant is intended for meeting shortfalls in electricity supply due to transmission outages, to compensate for low water conditions which reduce the ability of the hydroelectric generating facilities to provide service and to provide supply in the event of delays in start-up dates of new generating projects.[2]

For the purpose of this forecast, the Ministry assumed approximately 2 petajoules of natural gas will be consumed annually at Burrard to meet emergency transmission outages. Beyond 1990, however, an additional allowance of about 3 petajoules is made for meeting generation shortfalls resulting from low water levels.

8.2.3 Refined Petroleum Products

Own use of RPP's is defined to include the requirements of refineries which have already been detailed in section 5.5 and liquefied petroleum gases (LPG) used by gas plants. As a best approximation, gas plant use of LPG's has been held constant at their 1982 value of 0.08 PJ.

8.3 Primary Energy Requirements

Primary energy requirements were derived by aggregating the total end-use energy requirements, distribution and transmission losses associated with the supply of natural gas and electricity, and the fuel consumed by oil refineries. In addition, the energy consumed in the form of thermal electricity was converted into primary fuel by using a conversion factor of 10.55 MJ per KwH and this was added into the primary energy totals shown in Table 8.10. The electricity estimates are correspondingly reduced to reflect the exclusion of thermal electricity.

---

[2] For planning purposes, B.C. Hydro assumes that Burrard could provide 3170 GWH annually - that is 11 PJ of electricity. This is viewed as a contingency rather than a continuous source of electricity supply.

The primary energy requirements in the province are expected to increase from 876.5 petajoules in 1981 to 1129.0 petajoules in 2000 indicating an annual average growth rate of 1.3 percent.

8.4 Primary Fuel Requirements

The total demand for primary fuels in British Columbia is forecast to increase from 905.0 petajoules in 1981 to 1301.8 petajoules in 2000 reflecting an annual average growth rate of 1.9 percent.

These estimates are summarized in Table 8.11 and are derived from the primary energy requirements forecast by adding requirements for natural gas as a feedstock and the non-energy related consumption of refined petroleum products. These feedstock and non-energy use requirements are detailed earlier in the relevant chapters.

The demand for natural gas is expected to experience a relatively healthy growth of about 4.1 percent per annum over the 1981-2000 period. Over the first half of the forecast period the growth rate is expected to be much higher around 7.1 percent per annum. This higher growth in natural gas demand is the result of the impact of several factors which include the extension of natural gas service to Vancouver Island starting

TABLE 8.10

PRIMARY ENERGY REQUIREMENTS FORECAST
BRITISH COLUMBIA

(PETAJOULES)

YEAR	NATURAL GAS	ELECT.	TOTAL RPP	OTHER	TOTAL REQTS
1978	162.143	140.719	346.642	195.357	844.861
1979	179.268	144.331	373.705	190.622	887.926
1980	182.436	150.019	388.196	202.290	922.941
1981	169.938	151.548	382.576	172.423	876.485
1982	170.121	153.587	347.315	174.593	845.616
1983	172.499	160.053	322.709	190.416	845.677
1984	176.046	166.654	316.269	194.536	853.505
1985	178.488	172.020	316.385	198.700	865.593
1986	188.553	172.147	314.158	192.502	867.360
1987	189.584	175.137	312.021	198.034	874.776
1988	193.859	180.277	314.113	208.386	896.635
1989	194.870	182.211	314.025	218.879	909.985
1990	195.474	191.719	317.301	225.233	929.727
1991	199.360	193.861	323.068	231.347	947.636
1992	201.833	197.339	330.350	232.530	962.052
1993	205.359	201.027	337.191	238.278	981.855
1994	209.611	205.284	344.389	238.807	998.091
1995	214.934	208.698	352.237	245.554	1021.423
1996	219.106	212.249	357.937	250.158	1039.450
1997	224.292	218.582	365.821	254.907	1063.602
1998	229.475	222.563	373.408	258.096	1083.542
1999	234.408	236.453	381.258	260.884	1113.003
2000	238.770	240.067	388.661	261.538	1129.036

ANNUAL GROWTH RATES

1981-1990	1.57	2.65	¯2.06	3.01	.66
1990-2000	2.02	2.27	2.05	1.51	1.96
1981-2000	1.81	2.45	.08	2.22	1.34

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

TABLE 8.11

PRIMARY FUEL REQUIREMENTS

(PETAJOULES)

YEAR	NATURAL GAS			ELECTRICITY	TOTAL RPP			OTHER	TOTAL
	ENERGY	NON ENERGY	TOTAL		ENERGY	NON ENERGY	TOTAL		
1978	162.143	.000	162.143	140.719	346.642	33.263	379.905	195.357	878.124
1979	179.268	.000	179.268	144.331	373.705	30.403	404.108	190.622	918.329
1980	182.436	.000	182.436	150.019	388.196	31.594	419.790	202.290	954.535
1981	169.938	.000	169.938	151.548	382.576	28.978	411.554	172.423	905.463
1982	170.121	5.682	175.803	153.587	347.315	17.928	365.243	174.593	869.226
1983	172.499	14.620	187.119	160.053	322.709	21.344	344.053	190.416	881.641
1984	176.046	15.457	191.503	166.654	316.269	24.086	340.355	194.536	893.048
1985	178.488	15.501	193.989	172.020	316.385	26.596	342.981	198.700	907.690
1986	188.553	15.546	204.099	172.147	314.158	28.747	342.905	192.502	911.653
1987	189.584	19.261	208.845	175.137	312.021	29.269	341.290	198.034	923.306
1988	193.859	101.007	294.866	180.277	314.113	29.930	344.043	208.386	1027.572
1989	194.870	116.242	311.112	182.211	314.025	30.691	344.716	218.879	1056.918
1990	195.474	119.259	314.733	191.719	317.301	35.303	352.604	225.233	1084.289
1991	199.360	123.776	323.136	193.861	323.068	36.085	359.153	231.347	1107.497
1992	201.833	123.839	325.672	197.339	330.350	36.922	367.272	232.530	1122.813
1993	205.359	123.904	329.263	201.027	337.191	37.816	375.007	238.278	1143.575
1994	209.611	123.969	333.580	205.284	344.389	38.748	383.137	238.807	1160.808
1995	214.934	124.036	338.970	208.698	352.237	39.694	391.931	245.554	1185.153
1996	219.106	124.105	343.211	212.249	357.937	40.655	398.592	250.158	1204.210
1997	224.292	124.175	348.467	218.582	365.821	41.619	407.440	254.907	1229.396
1998	229.475	124.246	353.721	222.563	373.408	46.432	419.840	258.096	1254.220
1999	234.408	124.318	358.726	236.453	381.258	47.403	428.661	260.884	1284.724
2000	238.770	124.392	363.162	240.067	388.661	48.362	437.023	261.538	1301.790

ANNUAL GROWTH RATES

1981-1990	1.57	.00	7.09	2.65	¯2.06	2.22	¯1.70	3.01	2.02
1990-2000	2.02	.42	1.44	2.27	2.05	3.20	2.17	1.51	1.84
1981-2000	1.81	.00	4.08	2.45	.08	2.73	.32	2.22	1.93

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

in 1986, the commitment of gas supplies for an LNG facility and provision of feedstock for an ammonia-urea plant in the province. Based on these considerations the demand for natural gas is forecast to increase from 170.0 petajoules (4368.6 million cubic metres) in 1981 to 363.2 petajoules (9335.8 million cubic metres) by the year 2000.

The primary fuel demand for petroleum products is forecast to increase from 411.6 petajoules (66 million barrels) in 1981 to 437.0 petajoules (70 million barrels) in 2000 indicating an annual average growth rate of 0.3 percent. Contributing to this growth is an anticipated increase in aluminum production by Alcan, which would create more demand for petroleum coke.

CHAPTER 9

CONVENTIONAL ENERGY SUPPLIES

9.0 Introduction

This chapter outlines the outlook for domestic conventional energy sources capable of meeting the province's energy requirements. The supply forecasts for different fuels incorporate different methodologies and assumptions.

Regarding electricity, only currently committed hydroelectric projects and energy purchases have been included in the estimate of B.C. Hydro's electricity supply. Thus, the resulting demand/supply balance suggests when future electricity capacity may be required on the B.C. Hydro system.

The province has adopted a set of criteria for determining whether surpluses of natural gas do exist within the province[1] and whether further exports of natural gas may occur without infringing upon the protection of domestic and already committed export consumers. The future supply of natural gas depends on the rate of exploration and development activity. Assumptions have been made regarding the level of those activities and the resulting supply forecast along with the forecast of demand for natural gas by domestic and committed export consumers are employed in the surplus determination criteria to determine the magnitude of the natural gas surplus. The results of the application of these tests, along with a discussion of relevant assumptions, will be presented in Chapter 10.

---

[1] "Commissioner Inquiry on British Columbia's Requirements, Supply and Surplus of Natural Gas and Natural Gas Liquids," George W. Govier, Victoria, 1982.

The province meets only about 25 percent of its requirements of crude oil from domestic sources, and is likely to require continued transfers of crude oil or petroleum products into the province in the foreseeable future. It is therefore assumed that the production of domestic oil is constrained only by the producibility of the resource. The forecast of domestic oil producibility along with a review of the production of heavy fuel oil from domestic petroleum refineries is presented in sections 9.3 and 9.4.

The production of hog fuel has been discussed in Chapter 5, and is summarized in section 9.5.

9.1 Electricity

9.1.1 Existing Supply

Provincial electricity supply is defined to include all hydroelectric generation capability and electricity generation capability at utility-owned thermal facilities. Thermal generation by industry is excluded because appropriate data are not available. Allowance for industrial self-generation has, however, been made in estimating industrial electricity requirements. Total provincial electrical supply is summarized in Table 9.1 where the capability of the B.C. Hydro system, the major supplier of electricity in the province, has been identified seperately.

B.C. Hydro's supply consists mainly of electricity from its hydraulic system but also includes the possibility of some natural gas fired thermal energy and energy purchases.[2] In Table 9.1, "other" supply includes hydroelectricity generated by Alcan, Cominco, West Kootenay Power and Light, and the forest industry.

The "firm" energy capability indicated for B.C. Hydro refers to electricity supply which would be available under critical water conditions,[3] while average capability would be that available under average water conditions.[4] Included in the estimates is output from the Revelstoke project which is expected to be in service by the end of 1984. It will add 6,800 GWh to B.C. Hydro's annual capability in critical water years and 7,870 GWh in average years.

Included as a component of B.C. Hydro's firm capability (also in the estimates of average capability) is the potential generation of 3,170 GWh/year at its Burrard thermal plant using natural gas available during summer months ("valley gas"). This plant would only be used if the need arose. Another component of B.C. Hydro capability is

---

[2] Gas fired thermal energy and purchases are included under firm supply capability since B.C. Hydro has assumed that these alternative sources would be required and are available in critical water years in order to achieve the 'Total Firm Energy Capability' on which Hydro bases its generation planning.

[3] Critical water conditions are defined as the most adverse recorded streamflow conditions on the B.C. Hydro system as a whole. Streamflow records run from the year 1940.

[4] "B.C. Hydro, 1983 Ten Year Electric System Plans and Evaluations (Summary Outline) April 1, 1983 to March 31, 1993", System Engineering Division, December 1982.

Table 9.1

Provincial Electricity Capability

(Gigawatt-hours)

Year	B.C. Hydro		Other	Total Provincial	
	Firm*	Average		Firm	Average
1983	38,795	42,565	12,000	50,795	54,565
1984	45,355	49,372	12,000	57,355	61,372
1985	47,320	51,730	12,000	59,320	63,337
1986	47,320	51,730	12,000	59,320	63,337
1987	47,320	51,730	12,000	59,320	63,337
1988	47,320	51,730	12,000	59,320	63,337
1989	47,320	51,730	12,000	59,320	63,337
1990	47,320	51,730	12,000	59,320	63,337
1991	47,320	51,730	12,000	59,320	63,337
1992	47,320	51,730	12,000	59,320	63,337
1993	47,320	51,730	12,000	59,320	63,337
1994	47,320	51,730	12,000	59,320	63,337
1995	47,320	51,730	12,000	59,320	63,337
1996	47,320	51,730	12,000	59,320	63,337
1997	47,320	51,730	12,000	59,320	63,337
1998	47,320	51,730	12,000	59,320	63,337
1999	47,320	51,730	12,000	59,320	63,337
2000	47,320	51,730	12,000	59,320	63,337

* Includes B.C. Hydro's estimates of "Purchases and Other" plus 3170 GWh per year of Burrard output. These numbers represent B.C. Hydro's "Firm Energy Capability" used for generation planning.

"Purchases and Other" totalling 2,200 GWh/year from sources such as Trans-Alta. and U.S. Utilities. Alcan may also be a source of additional energy, depending on its supply/demand balance at the time.

In addition, a recent agreement between British Columbia and Seattle concerning the Skagit Valley permits B.C. Hydro to raise its Seven Mile reservoir, thus increasing energy capability.[5] Once raised, this could add 155 GWh/year to firm capability and 197 GWh/year to average capability. However, it is not expected that Seven Mile would be raised until at least 1997, given the current system surplus.

9.1.2 Future Supply

There are numerous potential hydro and thermal projects which could be developed to increase provincial supply in the 1990's. None of these have been included in the forecast, however, since all projects over 20 MW are subject to government review and approval.

---

[5] On March 30, 1984, the Province of British Columbia and the City of Seattle signed an agreement to prevent flooding of the Skagit Valley. A treaty between the governments of Canada and the United States has also been concluded to implement this agreement. The agreement and treaty require British Columbia to export 318 GWh (at Blaine) of electricity per year, beginning January 1, 1986 and they allow British Columbia to raise the Seven Mile Reservoir and increase provincial electricity supply by about 155 GWh under critical and 197 GWh under average water conditions. The agreement continues in force until 2066 unless terminated by either party by giving five years notice, with the earliest possible termination date set at January 1, 1997.

Following completion of the Revelstoke project, B.C. Hydro's potential supply options could include those detailed in Table 9.2:

Table 9.2

Potential Hydroelectric Supply Options GWh/Year

	Critical	Average
Keenleyside	830	870
Murphy Creek	1,700	1,970
Peace Site C	4,740	4,770
Stikine-Iskut	13,160	15,190

Alcan has applied for Provincial approvals for the proposed Kemano Completion development. The company plans to increase existing Kemano generation to support new aluminum smelter developments noted elsewhere in this report. If this hydroelectric project were to be approved it could have a generation capability of as much as 5,000 GWh/year in average water years.

9.2 Marketable Natural Gas

In 1982, the Ministry undertook an Inquiry[6] into the requirements, supply and surpluses of natural gas and natural gas liquids. In the course of its work, the Inquiry examined the existing established reserves, the rate at which new reserves are discovered, the time profile for the connection of existing and established reserves and the rate at which reserves may deliver natural gas. This work established a profile of the ability of the province to provide natural gas under conditions where all natural gas which could be produced was assumed to be produced (maximum producibility) or alternately, where natural gas production was constrained by effective market demand. This latter case is referred to as the "supply tracking" case and will be examined in relation to the determination of the existence of a natural gas surplus in Chapter 10.

---

[6] "Commissioner Inquiry on British Columbia's Requirements, Supply and Surplus of Natural Gas and Natural Gas Liquids," George W. Govier, Commissioner, Victoria, May 1982.

The Petroleum Resources Division of the Ministry participated in the Inquiry as staff members and have subsequently provided more recent information and analysis. An update on the work of the Inquiry regarding the supply of marketable natural gas is provided below.

Remaining established reserves of marketable natural gas in British Columbia were estimated at about 239 billion cubic metres (9297 petajoules) at December 31, 1983. The Inquiry estimated remaining undiscovered potential reserves of 500 billion cubic metres in the Northeast of the province and a further 100 billion cubic metres in the Queen Charlotte-Tofino basin. The rate at which this undiscovered potential will be exploited will depend upon the level of exploration drilling activity.

In its analysis, the Inquiry examined a range of drilling activity from 100 to 500 wells per year. The Ministry in this forecast has assumed that 100 wells will be drilled in 1984, 200 wells in 1985 and 300 in 1986 and thereafter. Based on this scenario, the Petroleum Resources Division of the Ministry has developed a profile of maximum annual producibility of marketable natural gas in British Columbia. This production profile is presented in Table 9.3.

Total producibility is projected to increase from about 11.1 billion cubic metres in 1984 to 14.1 billion cubic metres by the end of the century. In the year 2000, producibility from reserve additions is forecast to constitute about 55 percent of total producibility.

It is important to note that these results assume that maximum production occurs and that market demand is sufficient to consume these volumes. If market demand were in fact lower than maximum producibility levels and the drilling activity selected were maintained, the province would be able to supply somewhat greater volumes of natural gas in the later years.

9.3 Crude Oil From Domestic Producers

The forecast of domestic crude oil supply was also developed by the Petroleum Resources Division of the Ministry. The forecast represents aggregate producibility from established reserves, anticipated new discoveries and supplies made available from future tertiary recovery operations.

The remaining established crude oil reserves in the province were estimated at 23.52 million cubic metres (907 petajoules) as of December 31, 1983. Forecasts of producibility from these established reserves were developed on a pool by pool basis and these individual forecasts were aggregated in

Table 9.3

Maximum Annual Producibility of Marketable Natural Gas
(millions of cubic metres)

Year	Connected	Unconnected	Additions Due to Drilling	Total
1984	11126.4	0	0	11126.4
1985	10681.3	377.2	0	11058.5
1986	10040.4	1131.8	0	11172.2
1987	9438	2587.9	67.6	12093.5
1988	8871.8	3666.9	235.4	12774.1
1989	8339.4	3666.9	600.2	12606.5
1990	7839.1	3666.9	1185.1	12691.1
1991	7368.7	4421.3	1418.8	13208.8
1992	6926.6	4421.3	2606.5	13954.4
1993	6234.0	4421.3	3346.3	14001.6
1994	5610.6	4583.4	4044.2	14238.2
1995	5049.5	4564.6	4720.7	14334.8
1996	4544.6	4491	5376.7	14412.3
1997	4090.1	4314.6	6009.1	14413.8
1998	3681.1	4028.4	6610.6	14320.1
1999	3313	3717.2	7168.6	14198.9
2000	2981.7	3437.2	7663.8	14082.7

determining the total producibility. Producibility from all but two major pools is exptected to decline. The supply from Stoddart West Belloy "C" and Eagle Belloy Unit 1, is forecast to peak in 1983 and 1984 respectively before experiencing a decline in their respective producibility levels. Producibility from established reserves is forecast to decline from 2.08 million cubic metres (79 petajoules) per year in 1982 to 0.41 million cubic metres (16 petajoules) in the year 2000. (Table 9.4)

The Ministry has assumed that discoveries of new oil will occur in one of two manners. "Normal" oil discoveries will provide additional reserves of approximately 0.64 million cubic metres (25 petajoules) per year beginning in 1982. In addition, the forecast also assumes that two major oil discoveries will be made with the first occurring in 1984 and the second in 1992. Each major new discovery is assumed to be similar in scale to the Eagle field discovery in 1976 and is assumed to contribute approximately 4.77 million cubic metres (184 petajoules) of reserves. Producibility from new oil discoveries is forecast to provide 0.76 million cubic metres (30 petajoules) annually by 1990 and 0.86 million cubic metres (33 petajoules) by 2000.

Tertiary oil recovery programs are forecast to contribute about 0.80 million cubic metres (31 petajoules) annually to domestic crude oil production by the year 2000.

The total supply of crude oil from indigenous sources is forecast to rise from 2.08 million cubic metres (81 petajoules) in 1982 to a peak of 2.12 million cubic metres (83 petajoules) in 1985 and decline gradually to 1.69 million cubic metres (66 petajoules) per year by 1992 as a result of

Table 9.4

Annual Domestic Crude Oil Producibility

(thousands of cubic metres)

Year	Established	Discoveries	Tertiary	Total
1982	2078.3	--	--	2078.3
1983	2011.5	19.0	58.0	2088.5
1984	1878.3	147.1	46.4	2071.8
1985	1792.2	286.5	34.7	2113.4
1986	1631.9	427.1	17.5	2076.5
1987	1463.3	564.4	11.7	2040.4
1988	1307.4	698.6	5.8	2011.8
1989	1174.2	730.7	5.8	1910.7
1990	1058.5	757.4	--	1815.9
1991	954.1	735.8	--	1689.9
1992	862.9	773.4	156.6	1792.9
1993	782.9	820.9	156.6	1760.4
1994	709.6	877.1	319.0	1905.7
1995	646.1	939.9	319.0	1905.0
2000	412.1	859.2	795.0	2066.3

reserve depletions and additions. Major new oil discoveries and the success of tertiary oil recovery programs combine to more than offset the impact of reserve depletions after 1992 and total annual producibility is forecast to reach 2.07 million cubic metres (84 petajoules) by the year 2000.

9.4 Heavy Fuel Oil

The production of heavy fuel oil has been forecast as a function of refinery capacity, refinery throughput and the quality of the crude oil feedstock. Table 9.5 presents a summary of the domestic heavy fuel oil production.

This forecast incorporates the assumption that the Kamloops petroleum refinery remains closed after 1983, reducing capacity by about 1500 cubic metres per day. This closure is offset by the inclusion of the expansion of the Shell refinery capacity to process an addition 1900 cubic metres per day of semi-processed synthetic crude from Alberta.

As shown in Table 9.5, the total production of refined petroleum products in British Columbia is forecast to increase from 363 petajoules in 1981 to 395 petajoules by the year 2000. This production forecast is developed on the premise that sufficient supplies of crude oil will be available to B.C. refineries to allow them to operate at a minimum of 75 percent of the total refinery capacity. The total throughput is expected to decline significantly during the 1980's. By the end of the 1990's, however, throughput is expected to reach 100 percent of capacity.

Table 9.5

Production of Heavy Fuel Oil by Domestic Refiners

(petajoules)

Year	B.C. RPP Production	Average HFO Yield (percent)	Production of HFO
1978	328.6	11.3	37.1
1979	361.8	12.0	43.4
1980	360.3	10.6	38.5
1981	363.3	11.3	41.0
1982	345.3	10.8	37.3
1983	334.8	10.2	34.1
1984	329.2	9.0	29.7
1985	326.9	8.4	27.6
1986	322.9	8.7	27.9
1987	320.6	8.9	28.7
1988	320.1	9.0	28.8
1989	319.5	8.9	28.5
1990	322.7	8.9	28.6
1991	328.2	8.9	29.2
1992	335.4	9.0	30.0
1993	342.8	9.0	30.9
1994	350.1	9.1	31.7
1995	357.8	9.1	32.6
1996	364.9	9.2	33.5
1997	373.1	9.2	34.4
1998	381.6	9.3	35.4
1999	389.8	9.3	36.4
2000	394.9	9.4	37.1

The average yield of heavy fuel oil is forecast on the basis of the anticipated changes in upgrading facilities and the quality of available crude oil. Both the consumption of synthetic crude at the Shell refinery and the recent investments in the Chevron refinery are expected to reduce the average heavy fuel oil yield significantly. Indeed heavy fuel oil as a proportion of throughput on an energy basis has already fallen from 11.3 percent in 1981 to an estimated 9.0 percent for 1984. Over the longer time period, however, the crude oil available to British Columbia refiners is expected to decline in quality,[7] with an associated increase in heavy fuel oil production. The decreased crude quality is expected to increase the average heavy fuel oil yield by about 1.0 percentage point from 8.4 percent in 1985 to 9.4 percent in the year 2000.

The total production of heavy fuel oil from domestic petroleum refineries is forecast to decline from 41 petajoules in 1981 to 28.6 petajoules in 1990 and then to increase to 37.1 petajoules in 2000.

9.5 Hog Fuel

Hog fuel consists of bark, sawdust and shavings which are generated in the manufacture of wood products. The methodology for determining the supply of hog fuel has been outlined briefly in Chapter 5. Supply is a function of the forecast of lumber production levels, the volume of bark associated with the timber production and the efficiency with which wood producers are able to convert timber into final products.

---

[7] The mix between heavy and light/medium domestic oil production is assumed to follow the profile set out in the background documents to the NEP Update (see Chapter 2, footnote 6).

Table 9.6 presents the forecast of hog fuel supplies on a regional basis. The supply of hog fuel is forecast to increase from about 158 petajoules in 1981 to about 187 petajoules in the year 2000. This growth occurs principally due to the recovery of the lumber market and the increase is moderated modestly by the increased consumption of sawdust and shavings as pulp furnish in the production of kraft pulp.

Table 9.6

Hog Fuel Supply
(Petajoules)

Year	S. Coast	N. Coast	Interior	Total
1981	44.3	12.8	100.4	157.6
1982	39.2	11.3	107.4	158.3
1983	50.0	12.6	114.3	176.9
1884	53.5	13.5	116.5	183.5
1985	56.5	15.2	116.6	188.3
1986	52.7	13.4	111.2	177.3
1987	53.6	13.4	112.2	179.2
1988	55.7	14.4	114.3	184.4
1989	55.4	13.9	113.3	182.6
1990	54.8	13.8	112.3	180.9
1991	54.1	17.2	112.0	183.3
1992	57.1	17.9	113.4	188.4
1993	58.4	17.9	112.8	189.1
1994	58.0	17.9	113.6	189.5
1995	57.7	17.9	113.1	188.7
1996	57.5	17.9	112.8	188.2
1997	57.4	17.9	112.5	187.8
1998	57.2	17.9	112.2	187.3
1999	57.1	17.9	112.0	187.0
2000	57.1	17.9	112.0	187.0

CHAPTER 10

SUPPLY/REQUIREMENTS BALANCES

10.0 Introduction

This chapter provides an overview to the supply/requirement balances for the major energy types in British Columbia including electricity, natural gas, liquid hydrocarbons (refined petroleum products), heavy fuel oil and hog fuel. Since supplies of energy measure quantities at points of production, requirements have been defined, where applicable, to include transmission and distribution losses, and producer own-use.

In summary, it is anticipated that new electricity generation facilities will not be required in the province until early 1997 and sufficient surplus natural gas exists for the province to increase its commitment to the proposed LNG project to 50 percent. The province will continue as a net importer of liquid hydrocarbons - including heavy fuel oil (i.e. on average, surpluses are not anticipated); finally, sufficient hog fuel supplies exist in the province to meet requirements, except for the south coast where available supply is anticipated to be fully utilized.

10.1 Electricity

In this section the supply/demand balances for the total Province and the B.C. Hydro system are presented separately in Tables 10.1, through to 10.4. Provincial requirements have been defined to include sales of purchased electricity, export

TABLE 10.1

PROVINCIAL ELECTRICITY SUPPLY / DEMAND BALANCE

(GIGAWATT HOURS)

YEAR	TOTAL REQTS	SUPPLY	SURPLUS (DEFICIT)
1981	42129	49000	6872
1982	42699	50795	8096
1983	44648	50795	6147
1984	46482	57355	10873
1985	47973	59320	11348
1986	48326	59320	10995
1987	49157	59320	10164
1988	50584	59320	8736
1989	51122	59320	8199
1990	53763	59320	5558
1991	54641	59320	4679
1992	55607	59320	3713
1993	56632	59320	2689
1994	57814	59320	1506
1995	58762	59320	558
1996	59749	59320	-428
1997	61508	59320	-2188
1998	62614	59320	-3293
1999	66472	59320	-7152
2000	67476	59320	-8156

ANNUAL GROWTH RATES

1981-1990	2.75	2.15	-2.33
1990-2000	2.30	.00	.00
1981-2000	2.51	1.01	.00

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

sales to the city of Seattle, losses in transmission and distribution and own-use by utilities. Requirements of industries that generate their own electricity have also been added so that total requirements can be compared to the provincial supply estimates presented in Chapter 9. Provincial supply has been defined to include all existing and committed projects (e.g. Revelstoke) under critical water conditions on the B.C. Hydro system as well as firm supply capability from Alcan, Cominco/WKPL and industrial sources.

Projects which require Energy Project Certificates, such as Site C, Keenleyside, Murphy Creek, More Creek and Kemano Completion have been excluded from the supply estimates so that the timing and magnitude of new electricity projects can be easily identified. Tables 10.1 and 10.2 indicate that total provincial electricity requirements will grow at an average annual rate of 2.5 percent from 152 PJ in 1981 to 243 PJ by the year 2000 and given the provincial electricity supply, requirements will exceed supply sometime in 1996/97.

For the B.C. Hydro system alone, where requirements grow at an average annual rate of 2.7 percent, the in-service date for the next project is 1997 as shown in Tables 10.3 and 10.4.[1] This represents a slippage of almost nine years when compared with

---

[1] The difference in the in-service dates at the provincial level versus the B.C. Hydro system level is, for the most part, a result of including self-generated electricity requirements in provincial demand (i.e. requirements by a new aluminum smelter, which have been assumed to be met by Kemano Completion) but not in provincial supply. B.C. Hydro system requirements are for purchased electricity only.

TABLE 10.2

PROVINCIAL ELECTRICITY SUPPLY / DEMAND BALANCE

(PETAJOULES)

YEAR	TOTAL REQTS	SUPPLY	SURPLUS (DEFICIT)
1981	152	176	25
1982	154	183	29
1983	161	183	22
1984	167	206	39
1985	173	214	41
1986	174	214	40
1987	177	214	37
1988	182	214	31
1989	184	214	30
1990	194	214	20
1991	197	214	17
1992	200	214	13
1993	204	214	10
1994	208	214	5
1995	212	214	2
1996	215	214	¯2
1997	221	214	¯8
1998	225	214	¯12
1999	239	214	¯26
2000	243	214	¯29

ANNUAL GROWTH RATES

1981-1990	2.75	2.15	¯2.33
1990-2000	2.30	.00	.00
1981-2000	2.51	1.01	.00

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

TABLE 10.3

SUPPLY / DEMAND BALANCE ON THE B.C. HYDRO SYSTEM

(GIGAWATT HOURS)

YEAR	TOTAL REQTS	SUPPLY	SURPLUS (DEFICIT)
1981	31648	37000	5352
1982	32424	38795	6371
1983	33834	38795	4961
1984	35668	45355	9688
1985	37159	47320	10161
1986	37512	47320	9808
1987	38350	47320	8971
1988	39777	47320	7543
1989	40315	47320	7006
1990	40256	47320	7065
1991	41134	47320	6186
1992	42100	47320	5220
1993	43125	47320	4196
1994	44307	47320	3013
1995	45256	47320	2065
1996	46242	47320	1078
1997	48006	47320	¯686
1998	49112	47320	¯1792
1999	51071	47320	¯3750
2000	52075	47320	¯4754

ANNUAL GROWTH RATES

1981-1990	2.71	2.77	3.13
1990-2000	2.61	.00	.00
1981-2000	2.66	1.30	.00

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

TABLE 10.4

SUPPLY / DEMAND BALANCE ON THE B,C, HYDRO SYSTEM

(PETAJOULES)

YEAR	TOTAL REQTS	SUPPLY	SURPLUS (DEFICIT)
1981	114	133	19
1982	117	140	23
1983	122	140	18
1984	128	163	35
1985	134	170	37
1986	135	170	35
1987	138	170	32
1988	143	170	27
1989	145	170	25
1990	145	170	25
1991	148	170	22
1992	152	170	19
1993	155	170	15
1994	160	170	11
1995	163	170	7
1996	166	170	4
1997	173	170	-2
1998	177	170	-6
1999	184	170	-14
2000	187	170	-17

ANNUAL GROWTH RATES

1981-1990	2.71	2.77	3.13
1990-2000	2.61	.00	.00
1981-2000	2.66	1.30	.00

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

the Ministry's 1981 in service date estimate of late 1988. Much of the difference lies in the more pessimistic outlook for economic growth - particularly in the industrial sector. By way of example, the Ministry's previous forecast included requirements for two ferro-silicon plants to be completed by 1984 with a combined electricity requirement of 5.4 PJ per year. In contrast, the current forecast includes only one ferro-silicon plant which is of a much smaller scale requiring only 1.7 PJ annually and in operation by 1991. As well, electricity price increases are expected to be higher than in the previous forecast, depressing the growth in requirements in all sectors.

For this forecast it is assumed that B.C. Hydro will develop the remaining grid-connected major hydroelectric sites in the province except for the special case of Kemano Completion. As noted already, Tables 10.3 and 10.4 indicate requirements on the B.C. Hydro system will exceed supply sometime during 1997 and will require B.C. Hydro to build additional facilities (some supply options have been listed in Chapter 9).

The current load forecast suggests that Keenleyside, Murphy Creek would be required in the 1997/98 period and that Peace Site C would be needed by 1999. On the other hand if Peace Site C was constructed first another project would not be required before the end of the century.

10.2 Natural Gas

Unlike the supply and demand comparisons presented for other fuels in this chapter, the supply/demand balance for natural gas is ascertained using procedures developed specifically for evaluating natural gas surplus in the province.

In 1982, a Commissioner Inquiry[2] developed a set of criteria for determining the existence and the extent of a natural gas surplus, and the estimation of the volume of natural gas which could reasonably be allocated to export and to new industrial projects. The recommendations of the commissioner were subsequently adopted by the Government for use in the Natural Gas Allocation Process.

The Commissioner recommended that the procedures for evaluating the surplus of marketable natural gas be:

a) The determination of the Total Surplus at any point in time by application of an Extended Reserves Test, being a test for the current year supplemented by a ten-year, or so, projection of the surplus under the anticipated level of drilling activity leading to a judgement decision of the surplus at the relevant point in time.

---

[2] "Commissioner Inquiry on British Columbia's Requirements, Supply and Surplus of Natural Gas and Natural Gas Liquids," George W. Govier, Commissioner, Victoria, May 1982.

b) For determining the maximum annual rates at which the surplus could be produced, the application of a Producibility Test in the form which compares total forecast producibility with the total forecast domestic and export commitments to yield the Maximum Annual Surplus.

c) For evaluating a specific proposed export or energy use project, the application of a Producibility Test in the form which compares the forecast adjusted producibility resulting from projecting production at rates required to meet domestic requirements, existing export commitments, and the proposed project to determine whether the project could be accomodated and, if so, for what period of years within the judgement decision of the Total Surplus.

The Commissioner qualified procedure c) by proposing "...that the producibility tests be applied with judgement, recognizing uncertainties in the forecasts including the deliveries under export commitments".

As stated in b) above, the Producibility Test provides a comparison between total producibility (i.e. total supply) and total demand (including export commitments).

Results of the Producibility Test are shown in Table 10.5. The full producibility of natural gas shown in this table refers to the supply of marketable gas from domestic and extra-provincial sources. Domestic supply includes supplies from presently connected and unconnected established gas reserves in British Columbia and any additional supplies due to reserve additions and appreciations. The additions to the current established gas reserves would depend upon the level of drilling and exploration activity in the province. The scenario which underlies this forecast assumes that the number of wells drilled in the province will increase from 100 in 1984 to 200 in 1985, 300 in 1986 and thereafter.

The extra-provincial sources reported here constitute supplies from the Yukon and Northwest Territories and from northwestern and southwestern Alberta gas fields. The supplies to northeastern British Columbia include natural gas contracted to Westcoast Transmission Company by AMOCO, Pan-Alberta, and various Alberta producers for exports to the U.S. The southeastern British Columbia supplies from Alberta are purchased to meet the provincial domestic requirements in adjacent British Columbia areas.

As shown in Table 10.5 the total supply of natural gas available to the province is expected to decline from 13.9 billion cubic metres in 1984 to about 13.7 billion cubic metres in 2000. Contributing to this decline are the dwindling volumes of gas contracted from extra-provincial sources. The indigenous supplies, however, are forecast to increase from 11.61 billion cubic metres in 1983 to 13.7 billion cubic metres in 2000 primarily because of the optimistic outlook for natural gas and oil exploration activity in British Columbia over the forecast period.

Domestic demand for natural gas, on the other hand, is forecast to increase from 4.9 billion cubic metres in 1984 to 6.4 billion cubic metres in 2000. The total demand, however, increases from 14.0 billion cubic metres in 1984 to 15.2 billion cubic metres in 1989 and then tapers off to 13.7 billion cubic metres by 2000 with the termination of the exports commitments under GL-41 in 1989.

TABLE 10.5

PRODUCIBILITY TEST
PROJECT-ORIENTED FORM
HYPOTHETICAL EXPORT OR ENERGY USE PROJECT

1984 JUNE FORECAST - 50 PERCENT LNG
(300 WELL CASE)
(BILLION CUBIC METRES)

YEAR	FULL PRODUCIBILITY	DOMESTIC REQUIREMENTS	EXISTING EXPORTS	HYPOTHETICAL PROJECT	TOTAL DEMAND	PRODUCTION	ADJUSTED PRODUCIBILITY
1984	13.9	4.9	9.2	0.0	14.0	13.9	13.9
1985	13.9	4.9	8.8	0.0	13.7	13.7	13.9
1986	13.7	5.2	8.8	0.0	13.9	13.7	13.7
1987	14.3	5.2	8.8	0.1	14.1	14.1	14.3
1988	14.8	5.3	8.8	2.2	16.3	14.8	14.8
1989	14.3	5.3	7.3	2.6	15.2	14.3	14.3
1990	12.8	5.3	4.5	2.7	12.5	12.5	12.8
1991	13.8	5.4	2.9	2.8	11.1	11.1	13.8
1992	14.0	5.5	2.2	2.8	10.5	10.5	14.1
1993	13.8	5.6	5.4	2.8	13.7	13.7	14.2
1994	14.1	5.7	5.4	2.8	13.9	13.9	14.4
1995	14.1	5.8	5.4	2.8	14.0	14.0	14.5
1996	14.2	5.9	5.4	2.8	14.1	14.1	14.6
1997	14.1	6.1	5.4	2.8	14.2	14.2	14.6
1998	14.0	6.2	5.4	2.8	14.4	14.4	14.5
1999	13.9	6.3	5.4	2.8	14.5	14.3	14.3
2000	13.7	6.4	4.5	2.8	13.7	13.7	14.2

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

The comparison between total supply and total demand as presented in Table 10.5 indicates that the supply will fall short of the demand for some years in the 1980's. However, it should be noted that the export demand component of the total demand employed in this comparison assumes that the exports would be at their maximum authorized volumes as stipulated in the export licence GL-41. However, the present trends and a forecast study[2] undertaken on behalf of the Ministry indicate that the export demand would be significantly lower than the authorized maximum volumes and therefore available supplies of natural gas will always be sufficient to meet the demand, at least over the forecast period.

10.2.1 Surplus of Marketable Natural Gas

Using the procedures detailed by the Inquiry, the Commissioner determined that the surplus of marketable natural gas amounted to 59.8 billion cubic metres at Dec. 31, 1981 and that, if a favourable economic environment should increase drilling activity to 300 wells per year this surplus would grow to about 80.7 billion cubic metres by 1990. Subsequently, a number of proposals to use the projected surplus were evaluated by the Natural Gas Allocation Process and the Government allocated the surplus as follows:

11.3 billion cubic metres (400 Bcf) to an ammonia/urea project,
22.7 billion cubic metres (800 Bcf) to provide 25 percent of the requirements of an LNG project, and
51.0 billion cubic metres (1800 Bcf) to pipeline exports after 1989.

---

[2] "Projected Natural Gas Exports from British Columbia", Foster Associates Inc. Washington, D.C., January 1984.

In addition, a further 11.3 billion cubic metres (400 Bcf) was allocated to pipeline exports in 1998/99 conditional on there being adequate surplus demonstrated at that time.

Since the initial determination of the natural gas surplus, a number of underlying variables have altered with the result that the current and projected surplus defined by the Extended Reserves Test has changed.

The current surplus at the end of 1983 has risen to 71.2 billion cubic metres from 55.6 billion cubic metres projected in the initial calculations. A number of factors have contributed to this higher surplus. The gas reserves added in 1982 and 1983 were higher than originally expected and gas exports in 1982 and 1983 were substantially below the authorized volumes. In addition, the reduced activity in the pulp and paper industry and in the mining industry has caused the provincial requirements for 1983 to be slightly lower than the earlier estimates reported in the Govier Study.

Based on the Extended Reserves Test the gas surplus has been reestimated for each year starting in 1984 through to 2000. This recalculation indicates that the current surplus plus reserve additions that can be expected from exploration and development activity can cover the additional provincial commitments of:

a) 50 percent of an LNG project feedstocks in 1988 for 15 years as approved by the NEB;
b) feedstocks for an ammonia/urea facility assumed to start in 1987;

TABLE 10.6

EXTENDED RESERVES TESY FORECAST OF TOTAL SURPLUS
(CASE;50 PERCENT GAS TO LNG PROJECT)
(BILLION CUBIC METRES)

YEAR	REMAINING ESTABLISHED RESERVES	REMAINING EXTRA-PROVL RESERVES	TOTAL RESERVES	FORECAST MAINLAND REQUIREMENTS	25A(I) (I=1...24)	FFR ALLOWANCE	REMAINING EXPORT COMMITMENTS	TOTAL REQUIREMENTS ALLOWANCE	TOTAL SURPLUS
1984	238.62	15.21	253.83	4.86	121.54	10.00	51.08	182.62	71.21
1985	232.38	12.39	244.76	4.92	122.92	10.55	41.90	175.38	69.38
1986	231.41	9.56	240.97	4.87	121.77	11.11	33.23	166.11	74.86
1987	234.42	7.00	241.42	4.83	120.80	11.67	67.64	200.11	41.31
1988	236.34	4.71	241.05	4.89	122.24	12.22	58.63	193.08	47.97
1989	235.68	2.56	238.24	4.87	121.80	12.78	57.33	191.91	46.33
1990	234.56	.73	235.29	4.84	121.01	13.33	46.70	181.04	54.25
1991	234.88	.47	235.35	4.92	123.01	13.89	39.49	176.39	58.97
1992	236.19	.21	236.40	4.95	123.87	14.57	76.81	215.26	21.14
1993	237.71	.00	237.71	5.04	125.88	14.79	71.78	212.45	25.26
1994	235.42	.00	235.42	5.12	127.94	15.41	63.60	206.96	28.46
1995	232.66	.00	232.66	5.22	130.61	16.12	55.41	202.14	30.51
1996	229.43	.00	229.43	5.30	132.40	16.97	47.23	196.60	32.83
1997	225.75	.00	225.75	5.41	135.17	17.48	39.04	191.69	34.06
1998	221.63	.00	221.63	5.51	137.86	18.04	30.86	186.76	34.87
1999	217.06	.00	217.06	5.62	140.46	18.57	22.67	181.69	35.37
2000	212.07	.00	212.07	5.71	142.84	18.92	14.48	176.25	35.83

FFR; FIRM FUTURE REQUIREMENTS

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

c) NEB approved extension of pipeline exports in 1989 amounting to 9.6 billion cubic metres;
d) prospective pipeline exports in 1992 amounting to 43 billion cubic metres.

After satisfying these commitments there remains a surplus of gas reserves under the Extended Reserves Test of 21 billion cubic metres in 1992 as indicated in Table 10.6 This surplus is available to meet conditional pipeline exports, the remaining 5 years of LNG requirements and future allocations.

10.3 Total Liquid Hydrocarbons

Total liquid hydrocarbon requirements are defined to include the end-use of all refined petroleum products (heavy fuel oil, diesel, light fuel oil, stove, kerosene, motor gasoline, aviation gasoline, aviation turbine fuel and liquefied petroleum gases) non-energy use as determined in Chapter 7, plus refinery own-use requirements as discussed in Section 5.5 of Chapter 5. A liquid hydrocarbon supply forecast (crude oil and natural gas liquids) was provided by the Petroleum Resources Division of the Ministry. Tables 10.7 and 10.8 report the supply/requirements balance by cubic metres and petajoules respectively.

The province is forecast to continue its deficit position and to have to rely on increased interprovincial transfers of crude oil and refined petroleum products. Compared to the Ministry's previous forecast, it appears as if the deficit position has improved in the period to 1991 as lower economic growth combined with higher total energy costs has worked to reduce requirements growth. However, during the nineties, as a result of lower supply, the deficit position has worsened.

TABLE 10.7

SUPPLY/DEMAND BALANCE
FOR LIQUID HYDROCARBONS

(000 CUBIC METRES)

YEAR	DOMESTIC REQUIREMENTS NON-MOTIVE*	MOTIVE	TOTAL	DOMESTIC SUPPLY**	SUPPLY/DEMAND BALANCE
1981	3817	7235	11052	2209	-8843
1982	3380	6472	9852	2237	-7615
1983	3302	6005	9307	2276	-7031
1984	3357	5840	9198	2246	-6951
1985	3424	5822	9246	2283	-6963
1986	3105	6108	9213	2246	-6967
1987	3097	6057	9155	2217	-6938
1988	3172	6044	9216	2193	-7023
1989	3210	6016	9226	2086	-7140
1990	3424	5990	9414	1989	-7425
1991	3556	6024	9579	1872	-7708
1992	3691	6098	9789	1971	-7818
1993	3779	6216	9994	1935	-8060
1994	3867	6343	10211	2078	-8132
1995	3960	6484	10444	2075	-8369
1996	3994	6632	10626	2105	-8521
1997	4082	6782	10864	2134	-8730
1998	4244	6941	11185	2162	-9023
1999	4314	7109	11424	2190	-9234
2000	4369	7282	11651	2218	-9433

* INCLUDES NON-ENERGY USE

** DOMESTIC SUPPLY INCLUDES NATURAL GAS LIQUIDS

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

TABLE 10.8

SUPPLY/DEMAND BALANCE
FOR LIQUID HYDROCARBONS

(PETAJOULES)

YEAR	DOMESTIC REQUIREMENTS NON-MOTIVE*	MOTIVE	TOTAL	DOMESTIC SUPPLY**	SUPPLY/DEMAND BALANCE
1981	149.4	262.1	411.6	83.4	-328.2
1982	131.5	233.8	365.2	84.3	-280.9
1983	129.3	214.8	344.1	85.6	-258.5
1984	132.0	208.4	340.4	84.6	-255.8
1985	134.8	208.2	343.0	86.0	-257.0
1986	122.7	220.2	342.9	84.6	-258.3
1987	122.6	218.7	341.3	83.4	-257.9
1988	125.6	218.5	344.0	82.4	-261.6
1989	127.0	217.7	344.7	78.4	-266.3
1990	135.7	216.9	352.6	74.7	-277.9
1991	140.9	218.2	359.2	70.1	-289.1
1992	146.2	221.0	367.3	73.9	-293.4
1993	149.6	225.4	375.0	72.6	-302.4
1994	153.1	230.0	383.1	78.1	-305.0
1995	156.9	235.1	391.9	78.0	-313.9
1996	158.2	240.4	398.6	79.2	-319.4
1997	161.7	245.7	407.4	80.4	-327.1
1998	168.5	251.4	419.8	81.5	-338.3
1999	171.3	257.4	428.7	82.6	-346.1
2000	173.5	263.6	437.0	83.7	-353.3

* INCLUDES NON-ENERGY USE

** DOMESTIC SUPPLY INCLUDES NATURAL GAS LIQUIDS

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

Section 10.4 focuses on the special case of heavy fuel oil where in the previous forecast there had been some concern about the possibility of surpluses on the westcoast and the consequent displacement of natural gas in potential markets such as Vancouver Island.

10.4 Heavy Fuel Oil

The requirements for heavy fuel oil, as summarized in Table 8.7 of chapter eight, are brought together with refinery own use, losses, etc. and the supply of heavy fuel oil as outlined in Table 9.5 of Chapter 9. These are presented below in both cubic metres and petajoules in Tables 10.9 and 10.10 respectively.

In the Ministry's previous forecast, some concern was expressed with respect to possible surpluses of heavy fuel oil anticipated to occur in the early 1980's. The supply situation at that time was aggrevated by the importation of heavy fuel oil from California by coastal pulp and paper mills. In fact, the anticipated surplus did not materialize, in large part, due to a dramatic increase in marine bunkering (see Table 6.3.1) in the 1979 to 1982 period.

Moreover, the present forecasts of supply and demand indicate that a shortfall of heavy fuel oil is expected throughout the forecast period. The shortfall is expected to be supplied from either interprovincial transfers or imports from outside of Canada.

TABLE 10.9

SUPPLY/DEMAND BALANCE
FOR HEAVY FUEL OIL

(000 CUBIC METRES)

YEAR	TOTAL REQUIREMENTS*	B.C. HFO PRODUCTION	SUPPLY/DEMAND BALANCE
1981	1481	983	¯498
1982	1259	894	¯366
1983	914	819	¯95
1984	820	712	¯108
1985	846	660	¯185
1986	907	669	¯239
1987	938	687	¯251
1988	982	690	¯292
1989	998	663	¯316
1990	1030	683	¯347
1991	1065	699	¯366
1992	1103	719	¯384
1993	1127	739	¯388
1994	1162	759	¯403
1995	1207	781	¯426
1996	1211	802	¯409
1997	1245	824	¯421
1998	1280	847	¯432
1999	1313	872	¯441
2000	1336	892	¯444

* PRIMARY REQUIREMENTS

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

TABLE 10.10

SUPPLY/DEMAND BALANCE FOR HEAVY FUEL OIL

(PETAJOULES)

YEAR	TOTAL REQUIREMENTS*	B.C. HFO PRODUCTION	SUPPLY/DEMAND BALANCE
1981	61.8	41.0	¯20.8
1982	52.6	37.3	¯15.3
1983	38.2	34.2	¯4.0
1984	34.2	29.7	¯4.5
1985	35.3	27.6	¯7.7
1986	37.9	27.9	¯10.0
1987	39.1	28.7	¯10.5
1988	41.0	28.8	¯12.2
1989	41.7	28.5	¯13.2
1990	43.0	28.5	¯14.5
1991	44.4	29.2	¯15.3
1992	46.0	30.0	¯16.0
1993	47.0	30.8	¯16.2
1994	48.5	31.7	¯16.8
1995	50.4	32.6	¯17.8
1996	50.5	33.5	¯17.1
1997	52.0	34.4	¯17.6
1998	53.4	35.4	¯18.0
1999	54.8	36.4	¯18.4
2000	55.8	37.2	¯18.5

* PRIMARY REQUIREMENTS

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

The supply and demand of heavy fuel oil is pivotal in determining the volume of natural gas which will be consumed by the pulp and paper mills on Vancouver Island.[6] As outlined in the Natural Gas Supply to Vancouver Island Technical Report, a surplus of domestic production of heavy fuel oil would result in price discounting with the result that natural gas (in the absence of firm contracts) would be backed out until the excess supply had been dissipated.

It has been assumed that the heavy fuel displaced from Vancouver Island pulp and paper mills would find its way into the marine bunker market. Consequently, total heavy fuel oil requirements do not fall in 1986 when natural gas service to Vancouver Island begins.

On the supply side, B.C. refineries have instituted measures to reduce the production of heavy fuel oil per barrel of throughput. These initiatives, when coupled with the dramatically lower throughput brought on by reduced economic activity and conservation in light of the high oil prices in the 1979-1982 period, have resulted in substantially lower domestic supplies of heavy fuel oil when compared to the 41 PJ in 1981. It is anticipated that economic recovery in combination with lower qualities of crude over time will work to increase local refinery production of heavy fuel oil. By the end of the century production is anticipated to be at 1982 levels.

---

[6] For the purposes of this forecast, the southern route of the Vancouver Island gas pipeline as detailed in the Abercrombie report has been assumed, and will provide natural gas service to Crofton, Elk Falls, Harmac and Port Alberni. A northern route selection would also provide gas service to Powell River.

10.5 Hog Fuel

Table 10.11 presents the hog fuel supply demand balance determined from the analysis presented in Chapter 5. The forecast of supply is based on the methodology outlined in sections 5.1.1 and 5.1.2. The hog fuel demand includes the needs of both the wood products industry and the pulp and paper mills. Where insufficient supplies of hog fuel are available on a regional basis, the quantity consumed by mills is constrained.

TABLE 10.11

HOG FUEL SUPPLY AND DEMAND BALANCE

(PETAJOULES)

	DEMAND			SUPPLY			BALANCE		
YEAR	S, COAST	N, COAST	INTERIOR	S, COAST	N, COAST	INTERIOR	S, COAST	N, COAST	INTERIOR
1981	40.3	1.7	22.4	44.3	12.8	100.4	4.1	11.2	78.0
1982	37.6	2.0	25.5	39.2	11.3	107.4	1.6	9.3	81.9
1983	45.9	2.7	29.1	50.0	12.6	114.3	4.1	10.0	85.2
1984	46.4	3.2	28.4	53.5	13.5	116.5	7.0	10.3	88.1
1985	48.5	3.8	29.2	56.5	15.2	116.6	7.9	11.5	87.5
1986	46.5	3.9	27.1	52.7	13.4	111.2	6.2	9.5	84.0
1987	47.1	4.3	28.4	53.6	13.4	112.2	6.4	9.1	83.8
1988	49.1	4.9	29.7	55.7	14.4	114.3	6.6	9.5	84.5
1989	50.1	5.4	34.8	55.4	13.9	113.3	5.3	8.5	78.5
1990	50.8	5.9	35.7	54.8	13.8	112.3	3.9	7.9	76.5
1991	51.2	6.4	38.2	54.1	17.2	112.0	3.0	10.9	73.9
1992	53.4	6.6	37.0	57.1	17.9	113.4	3.7	11.4	76.3
1993	54.9	6.7	38.6	58.4	17.9	112.8	3.4	11.2	74.2
1994	55.7	6.9	37.8	58.0	17.9	113.6	2.3	11.0	75.9
1995	56.3	6.9	38.9	57.7	17.9	113.1	1.4	11.0	74.2
1996	57.2	6.9	39.9	57.5	17.9	112.8	.3	11.0	72.9
1997	57.4	6.9	40.7	57.4	17.9	112.5	.0	11.0	71.8
1998	57.2	6.9	41.2	57.2	17.9	112.2	.0	11.0	71.0
1999	57.1	6.9	42.0	57.1	17.9	112.0	.0	11.0	69.9
2000	57.1	6.9	42.1	57.1	17.9	112.0	.0	11.0	69.9

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES,
JUNE 1984

Queen's Printer for British Columbia ©
Victoria, 1984

cc